VOLUME II

TRANSCRIPT OF RECORD

Supreme Court of the United States

OCTOBER TERM, 1964

No. 644

THE UNITED GAS IMPROVEMENT COMPANY, PETITIONER,

vs.

CONTINENTAL OIL COMPANY, ET AL.

No. 693

FEDERAL POWER COMMISSION, PETITIONER,

vs.

M. H. MARR, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FIFTH CIRCUIT

NO. 644 PETITION FOR CERTIORARI FILED NOVEMBER 2, 1964
NO. 693 PETITION FOR CERTIORARI FILED NOVEMBER 16, 1964
CERTIORARI GRANTED JANUARY 18, 1965

TABLE OF CONTENTS

IN THE

United States Court of Appeals

For the Fifth Circuit

Nos. 20560, 20564, 20582, 20587, 20829, 20846, 20847, and 20591

M. H. Marr, Sun Oil Company, Continental Oil Company, General Crude Oil Company, Texas Eastern Transmission Corporation, *Petitioners,*

v.

Federal Power Commission, *Respondent.*

On Petitions to Review Opinions and Order. f the Federal Power Commission

---

JOINT APPENDIX

(Volume II)

3708

Docketed June 23, 1959

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Opinion No. 322

In the Matters of	Docket Nos.
Texas Eastern Transmission Corporation	G-12446
Texas Eastern Transmission Corporation (formerly Texas Eastern Penn-Jersey Transmission Corporation)	G-12447
Continental Oil Company	G-12432

Opinion and Order Issuing Certificate of Public Convenience and Necessity and Modifying and Adopting Initial Decision of Presiding Examiner

Issued: June 23, 1959

3709

APPEARANCES

For Texas Eastern Transmission Corporation and Texas Eastern Penn-Jersey Transmission Company

Jack D. Head, Esquire, Houston, Texas
W. D. Deakins, Jr., Esquire, Houston, Texas
Frank E. Trobaugh, Esquire, West Frankfort, Illinois
Charles E. McGee, Esquire, Washington, D. C.
Francis H. Caskin, Esquire, Washington, D. C.
R. E. Christiansen, Esquire, Washington, D. C.

For Continental Oil Company

Roland B. Voight, Esquire, Houston, Texas
Gene Woodfin, Esquire, Houston, Texas

For M. H. Marr

D. C. Wertz, Esquire, Dallas, Texas

For Sun Oil Company
Herf M. Weinert, Esquire, Beaumont, Texas
Martin A. Row, Esquire, Dallas, Texas
Robert E. May, Esquire, Washington, D. C.

For General Crude Oil Company
D. F. Morse, Esquire, Houston, Texas

For Public Service Commission of the State of New York
Kent A. Brown, Esquire, Albany, New York
Lawrence M. De Vore, Esquire, Albany, New York
Barbara M. Suchow, Attorney, Albany, New York
Charles J. Cox, Esquire, Albany, New York

3710

For Ohio Fuel Gas Company
W. F. Laird, Esquire, Columbus, Ohio
Brooks E. Smith, Esquire, New York City
William C. Hart, Esquire, New York City
Frederick Clark, Esquire, New York City

For Manufacturers Light and Heat Company
William Anderson, Esquire, Pittsburgh, Pennsylvania
Brooks E. Smith, Esquire, New York City
William C. Hart, Esquire, New York City
Frederick Clark, Esquire, New York City

For Texas Gas Transmission Corporation
Christopher T. Boland, Esquire, Washington, D. C.
Thomas F. Brosman, Esquire, Washington, D. C.
Thomas F. Ryan, Esquire, Washington, D. C.
William E. Feldhaus, Esquire, Owensboro, Kentucky

For Public Service Electric and Gas Company
Edward S. Kirby, Esquire, Newark, New Jersey
J. Harry Mulhern, Esquire, Newark, New Jersey
James R. Lacey, Esquire, Newark, New Jersey
William R. Duff, Esquire, Washington, D. C.
Frederick M. Broadfoot, Esquire, Newark, New Jersey

For Brooklyn Union Gas Company

J. David Mann, Esquire, Brooklyn, New York
Edwin F. Russell, Esquire, Brooklyn, New York
Robert B. Lisle, Esquire, Brooklyn, New York
Harry G. Hill, Jr., Esquire, Brooklyn, New York

For Equitable Gas Company

John T. Brown, Esquire, Pittsburgh, Pennsylvania
Donald I. Moritz, Esquire, Pittsburgh, Pennsylvania

For Philadelphia Electric Company

Vincent P. McDevitt, Esquire, Philadelphia, Pennsylvania
Eugene J. Bradley, Esquire, Philadelphia, Pennsylvania
Samuel G. Miller, Esquire, Philadelphia, Pennsylvania

For Consolidated Natural Gas System Companies

C. W. Cooper, Esquire, New York, New York
George C. Williams, Esquire, Cleveland, Ohio
Norman A. Flaningam, Esquire, Washington, D. C.

3711

For United Gas Improvement Company

J. David Mann, Jr., Esquire, Washington, D. C.
John E. Holtzinger, Jr., Esquire, Washington, D. C.

For Elizabethtown Consolidated Gas Company

William M. Wherry, Esquire, New York City

For New Jersey Natural Gas Company

Sidney M. Schreiber, Esquire, Newark, New Jersey

For the Staff of the Federal Power Commission

Orson L. Huntsman, Esquire, Washington, D. C.

3712

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Jerome K. Kuykendall, Chairman; Frederick Stueck, Arthur Kline and John B. Hussey.

In the Matters of	Docket Nos.
Texas Eastern Transmission Corporation	G-12446
Texas Eastern Transmission Corporation (formerly Texas Eastern Penn-Jersey Transmission Corporation)	G-12447[1]
Continental Oil Company	G-12432

OPINION NO. 322

Opinion and Order Issuing Certificate of Public Convenience and Necessity and Modifying and Adopting Initial Decision of Presiding Examiner

(Issued June 23, 1959)

Texas Eastern Transmission Corporation (Texas Eastern) here seeks a certificate of public convenience and necessity under subsections (c) and (e) of Section 7 of the Natural Gas Act (Act) authorizing the expansion of its pipeline system capacity north and east of Opelousas, Louisiana by 101,660 Mcf per day (14,73 psia), to render additional service to eleven existing customers.[2] The basic

[1] Texas Eastern Penn-Jersey Transmission Corporation (Penn-Jersey) filed the application in Docket No. G-12447. This company, which was a wholly-owned subsidiary of Texas Eastern, has since merged with Texas Eastern, pursuant to Commission authorization in Docket No. G-14870; and reference to Texas Eastern or to its application herein includes, where appropriate, reference to Penn-Jersey or to its application.

[2] The customer companies and the volumes of gas they will receive are set forth in ordering paragraph (A) hereinafter.

question in this case, before us on the omission of the intermediate decision procedure, is whether Texas Eastern's project in its present modified form, including reliance on Texas Eastern's acquisition of the Bayne Field leases instead of its purchase of the gas therefrom under gas purchase contracts with the producers, is required by the public convenience and necessity and otherwise meets the requirements of Section 7(e) of the Act.

This is the second stage in these proceedings. In the first stage, the four producers which proposed to supply Texas Eastern the gas for this service—Continental Oil Company (Continental), M. H. Marr (Marr), Sun Oil

3713

Company (Sun) and General Crude Oil Company (General Crude)—sought certificates to sell Texas Eastern gas produced in the Rayne Field in Acadia Parish in southern Louisiana. The Rayne Field is one of the few large and fully developed gas reserves not presently committed to and serving a market. The gas purchase contracts provided for an initial price to Texas Eastern of 22.6 cents per Mcf, plus 1.3 cents tax reimbursement.

Relying on this gas as a part of its gas supply, Texas Eastern proposed by means of additional facilities estimated to cost approximately $48,600,000, to expand its system, which extends from gas fields in Louisiana and East Texas, in order to render increased service to existing customers principally in the middle Atlantic states.

A hearing was had on these applications and by his initial decision issued April 15, 1958, the presiding examiner would have granted these proposals of Texas Eastern and the producers. Exceptions were filed by staff counsel, certain distributing company customers of Texas Eastern, and the New York Public Service Commission, objecting principally to the examiner's conclusion that the public convenience and necessity required certification of these

projects at the initial prices provided for in the producer contracts, and his refusal to attach a condition to the producer certificates reducing those prices.

While the matter was pending before the Commission on these exceptions, Texas Eastern was negotiating with the producers for changes in their contracts, and it initiated the second stage of these proceedings by filing on September 8, 1958, a petition to reopen the hearing and to amend its certificate applications. In support of this request, the company stated that after exceptions had been filed to the examiner's decision, three of the producers—Sun, General Crude and Marr—had served notice of cancellation of their gas sales contracts with Texas Eastern and filed notice of the withdrawal of their certificate applications. These contracts cover approximately 45 percent of the total Rayne Field gas reserves underlying Texas Eastern's project. Texas Eastern stated that it had negotiated with the producers for the purchase of the leasehold interests formerly committed to the contract between them and Texas Eastern. It stated that the necessary final documents were being prepared, and requested opportunity to show in the reopened proceedings the benefits to the public which would accrue from this arrangement. In addition, Texas Eastern stated that it desired to modify the design of certain of its facilities, and requested opportunity to substantiate the proposed modifications. It also requested temporary authority to construct the facilities it proposed, as modified.

Thereafter, Texas Eastern modified its lease purchase agreements with the producers on two different occasions, eventually entering into agreements to acquire the gas, as set forth in the Second and Third Supplements to its petition to reopen hearing filed on December 5 and 15, 1958, respectively. In the latter filing, Texas Eastern advised the Commission that it had acquired the right to purchase the entire working interest

of Continental, Marr, Sun and General Crude in the Rayne Field leases, under the terms and conditions of the final Lease Purchase Agreement dated December 4, 1958, which it filed with the Commission.

There was no opposition to these supplemental petitions and by order issued February 19, 1959, we reopened the proceedings for the reception of evidence upon the Lease Purchase Agreement dated December 4, 1958, and upon the proposed modifications to Texas Eastern's facilities.

Hearings were had in the reopened proceeding in March, 1959, and there being no opposition thereto, by order issued April 6, 1959, we granted Texas Eastern's motion to omit the intermediate decision procedure, bringing the case before us for decision.

On December 5, 1958, we had granted Texas Eastern temporary authority to construct and operate certain facilities which, with facilities previously authorized on a temporary basis, enabled the company to increase the maximum daily delivery capacity of its system by 101,660 Mcf of gas per day. We did not grant Texas Eastern authority to construct and operate the facilities to attach the Rayne Field reserves, however.

The Public Convenience and Necessity

In his initial decision issued April 15, 1958, the presiding examiner concluded that certificates should issue to Texas Eastern and the producers authorizing the projects they then proposed. Except as to two matters hereinafter disposed of,[3] exceptions to the examiner's decisions were di-

[3] One of the producers, Sun, excepted to the examiner's attaching conditions to the producer certificates requiring the filing of applications for rate increases for future escalation increases. In the light of this opinion this question is now moot. In addition, exceptions were filed to the lack of any findings by the examiner with respect to the economic feasibility of Texas Eastern's project. This matter is discussed hereinafter.

rected solely to his conclusion that the producers' sales were required by the public convenience and necessity at the 22.6-cent initial price proposed, and to the several questions related to this issue. The producer applications have now been withdrawn, excluding Continental's, and except for the proposed acquisition of the Rayne Field leases, Texas Eastern's project remains in most basic respects unchanged by the amendments the company proposed in the reopening hearing.

We conclude that the findings and conclusions of the presiding examiner which are still applicable to Texas Eastern's modified project are correct and substantially supported by the evidence and we shall adopt them as our own. As to the modifications proposed by Texas Eastern, in

3715

our judgment the modified project, as evidenced by the earlier record and the record in the reopened hearing, is in each of its several aspects required by the public convenience and necessity and otherwise meets the requirements of the Act.

Markets and financing.—We find, as did the examiner, that there is a market for the additional volumes of gas which Texas Eastern will make available by means of the additional facilities proposed herein. No party has expressed any opposition to the sales to the distributing companies in the volumes and at the prices proposed by Texas Eastern under the modified proposal. Likewise, the evidence demonstrates and we find that Texas Eastern's ability to finance the proposed facilities, as modified, is sufficiently well-established for purposes of this proceeding; in fact, a considerable portion of the facilities had been constructed under temporary authorization at the time of the reopened proceedings.

Facilities.—We also find that the facilities proposed by Texas Eastern, as modified, are adequate to transport the additional volume of gas, and their design and estimated cost are reasonable.[4] No opposition has been expressed thereto by any party. The modifications proposed and supported at the reopened hearing result from the present availability of pipe which the company could not secure earlier, and the modified facilities have several advantages over the previous design. Although estimated capital costs for the facilities proposed by Texas Eastern are increased by $456,000 to a total of $49,088,000, the record shows that annual operating and maintenance expenses will be reduced approximately $358,100 as a result of the elimination of the compression at both the Wheelersburg and Berne Stations on the Texas Eastern system and Station E on the former Penn-Jersey system and the substitution

---

[4] Texas Eastern would modify its project by the following changes in the main-line facilities described on page 7 of the presiding examiner's initial decision issued April 15, 1958, as more fully set forth in the company's application, as amended:

1. Construct 12.5 miles of 30" pipeline loop on the intake side of the Wheelersburg, Ohio, compressor station and eliminate one 7,600 H.P. gas turbine driven centrifugal compressor previously proposed to be installed at Wheelersburg, Ohio.

2. Construct 16.3 miles of 30" pipeline loop on the intake side of the Berne, Ohio, compressor station and eliminate one 7,600 H.P. gas turbine driven centrifugal compressor previously proposed to be installed at Berne, Ohio.

3. Install an additional 13,600 H.P. in the Union Church Station, Jefferson County, Mississippi, instead of 12,300 H.P. as previously proposed, making a total horsepower at that station of 16,210 in place of 14,910.

4. Respecting the facilities proposed in the application of Penn-Jersey and as described on page 8 of the examiner's decision aforesaid, construct 12.5 miles of 30" pipeline loop between the compressor station at Bechtelville, Pennsylvania and Lambertville, New Jersey and eliminate one 13,400 H.P. gas turbine driven centrifugal compressor station previously proposed to be installed at Station E, Bucks County, Pennsylvania.

of the pipeline loops therefor. In addition, there will be a reduction in cost of $260,000 resulting from a reduction in gas used for compressor station fuel, so that the total estimated savings under the modified proposal will approximate $618,000 annually.

Gas supply and acquisition of Rayne Field reserves.— Turning to the question of gas supply, as indicated previously, Texas Eastern proposed at the first hearing to secure the gas for its project from four producers in the Rayne Field, at an initial price of 22.6 cents per Mcf, plus 1.3 cents tax reimbursement, with contract escalations as enumerated below. However, Texas Eastern now proposes to supply the project's gas needs by purchasing the oil and gas leases and related properties of Continental, Sun, Marr, and General Crude (hereinafter referred to as Continental, *et al.*), insofar as they apply to the proved reserves.

The three companies which filed exceptions to the examiner's decision objecting to the producer prices for gas under Texas Eastern's original proposal interposed no objection to the acquisition of and reliance on the Rayne Field reserves by Texas Eastern, either from the point of view of the price of gas to the company under its revised proposal or otherwise. Virtually the only opposition to Texas Eastern's revised project comes from the New York Public Service Commission. In essence, the New York Commission's position appears to be that in order to justify certification of Texas Eastern's modified project, a record must be made justifying the cost to Texas Eastern of the Rayne Field leases, which showing in turn must be based on a justification of the costs thereof to the producers. Thus the New York Commission requests that this proceeding be remanded to the examiner to "determine upon what price for the acquisition of the Rayne Field

leaseholds, public convenience and necessity would require authorization of the related construction herein proposed by Texas Eastern," contending that this is "the Commission's only opportunity to require producer disclosure of the costs associated with this gas and their relation to the sale price" of these leases.

In our judgment, the record in this case amply supports the conclusion that the elements of public convenience and necessity are satisfied by Texas Eastern's modified project, without examining into the cost to Texas Eastern of the Rayne Field leases to the extent advocated by the New York Commission. Texas Eastern has not filed an application for a

3717

certificate authorizing the acquisition of the Rayne Field leases and we have no authority to issue such a certificate. However, we have considered all the circumstances pertaining to the company's acquisition of the Rayne Field leases and the effects of this transaction on the need and convenience of the public proposed to be served, including the extent and accessibility of this gas supply; the benefits thereof in enabling Texas Eastern to meet consumer demands; the terms and conditions of the lease sale and purchase agreements including the price to Texas Eastern of the gas thereunder; the claimed savings accruing to Texas Eastern from acquiring the leases rather than purchasing the gas under gas purchase contracts; and the other factors present here. And we conclude that the company's modified project, as it would include and rely on the acquisition of the Rayne Field leases, is required by the public convenience and necessity and otherwise meets the requirements of Section 7(e) of the Act.

First summarizing briefly the arrangement under which Texas Eastern would purchase the Rayne Field leases, the pertinent agreements are contained in Exhibit M-14, *et*

seq., in the reopened proceedings. Louisiana Gas Corporation, a Delaware corporation which Texas Eastern caused to be formed for the purpose, is to acquire from Continental, *et al.*, under a Lease Sale Agreement dated December 4, 1958, between these parties (Exh. M-14 I), all the oil, gas and mineral leases, the surface leases, options and rights-of-way, together with all wells and related lease and well equipment (surface and subsurface), gathering and flow lines, etc., owned by Continental, *et al.*, in the Rayne Field. Continental, *et al.*, will convey its rights in the leases under the terms of the Assignment and Conveyance (Exh. M-14 1), at the time the four conditions set out in Exhibit M-14 I, page 1, are met or waived.[5] At that time Louisiana Gas will pay to Continental, *et al.*, the sum of $12,420,500 in cash and will simultaneously make 16 serial promissory notes to each of the sellers payable over a 16-year period in the total amount of $121,975,200 as the balance of the purchase price for the leases (Exh. M-21). The notes will be secured by an Act of Mortgage and Pledge (Exh. M-20), which will be executed by Louisiana Gas Corporation to each of the sellers to secure

[5] These conditions require (1) approval by Louisiana Gas Corporation of Continental, *et al.'s* title to the leasehold interests; (2) receipt by Continental, *et al.* from the Internal Revenue Service of a ruling in writing that the gain from the sale of the leasehold interests will be considered a gain from the sale of a capital asset held more than six months under Section 1231 of the Internal Revenue Code of 1954; (3) issuance by the Federal Power Commission of certificates, satisfactory to Continental, *et al.* and Louisiana Gas Corporation, necessary to enable the taking of Louisiana Gas Corporation's gas from the Rayne Field and transporting it to market; and (4) the securing by Continental, *et al.* of the dismissal of their certificate applications filed with the Commission for the sale of gas to Texas Eastern as proposed in the earlier proceedings.

It appears that of these conditions, the only ones remaining to be met are (3) with respect to the four producers and (4) with respect to Continental alone.

the payment of the notes. Continental, *et al.*, will retain a production payment out of the liquids produced with the gas and will also reserve the leasehold rights as to oil and deeper gas production.[6]

By the terms of the Lease Purchase Agreement (Exh. M-14), Louisiana Gas will in turn assign and convey the leaseholds and other interests it acquires from Continental, *et al.*, to Texas Eastern for a cash consideration of $12,-420,500 payable at the time of closing. In the Form of Conveyance from Louisiana Gas to Texas Eastern (Exh. M-14 II), it is provided that the properties and interests acquired by Louisiana Gas from Continental, *et al.*, will be conveyed to Texas Eastern subject to (a) the reservations, terms and provisions of the Assignment and Conveyance from Continental, *et al.*, to Louisiana Gas, and (b) the Acts of Mortgage and Pledge covering the properties and interests conveyed, executed by Louisiana Gas to secure Continental, *et al.*, in the payment of the promissory notes in the principal sum of $121,975,200.[7] The conveyance to

[6] The pertinent provisions of the agreement as to these reserved rights are as follows (Exh. M-14 1): All leasehold rights below the Nodosaria "A" Sand (which is the deepest known productive sand), and all leasehold rights to the oil and other minerals, except gas and condensate, are reserved by Continental, *et al.* (2) The production payment reserved by Continental, *et al.*, covers the separator liquids and natural gas liquids and is owned and payable in the proportions which Continental, *et al.*, own in the leasehold rights which are to be conveyed. (3) Texas Eastern will be entitled to deduct from the production payment an amount sufficient to recover the cost of producing and operating the leasehold rights, gathering lines and separator facilities and all taxes levied against the separator liquids plus a fixed sum of $4,000 per month. The production payment will continue in effect until the gas produced and saved equals 613,406,770 Mcf measured after the condensate has been removed. Thereafter the production payment will cease and Texas Eastern will be entitled to retain the full amount of the proceeds from the sale of the liquids.

[7] Texas Eastern will also pay an estimated $46,669,300 for the royalty and minority interest portion of the leases at an assumed average price of 22.6 cents per Mcf of gas.

Texas Eastern will be subject to the obligation of the promissory notes, the Acts of Mortgage and Pledge securing the payment thereof and a Vendor's Lien and Privilege of Continental *et al*. However, it is expressly provided that Texas Eastern does not assume any personal liability on the notes or agree to pay any deficiency in the event of foreclosure.

3719

From the point of view of adequacy of gas supply, we find that with the additions Texas Eastern proposes, including those referred to in the examiner's decision, the company's gas supply will be reasonably adequate in reserves and deliverability to support the service proposed and the demands on the company's system.

The Rayne Field leases alone are extremely important and desirable additions to the company's gas supply. The Rayne Field, with recoverable reserves estimated at 988,771,000 Mcf of gas, contains one of the largest single reserves in southern Louisiana. Further, there was evidence of possible additional reserves in untested sands covered by the lease rights to be acquired by the company. Thus there is a good probability that the unit cost of gas to Texas Eastern from the Rayne Field reserves will be even less than the cost computed by the company on the record herein, as discussed below, with consequent additional benefits to the consumer.

Furthermore, the leases are reasonably convenient to Texas Eastern's pipeline, the Rayne Field being only some 22 miles south of Texas Eastern's 30-inch Beaumont to Kosciusko tie line. Thus the company will be able to connect this major gas reserve to its system for a relatively small amount, as contrasted with the many millions of dollars of capital costs involved in laying laterals to the offshore and bay water locations of the only comparable un-

committed gas reserves in Louisiana. Moreover, deliveries can commence as soon as this connecting line is constructed.

In addition, in considering Texas Eastern's modified project, the desires and needs of the company's customers must be kept in mind, as well as the effects on them of the modifications proposed. Texas Eastern is no longer relying on the gas purchase contracts with the producers which were formerly available to it, and on this record, if the Rayne Field gas is to be made available to Texas Eastern's system, it will be on the basis of the lease acquisition agreements which underlie the modified project. As discussed hereinabove, there is a market demand for the gas Texas Eastern proposes to sell herein. The sales by Texas Eastern to its eleven distributing company customers will be made under longe-term service agreements and firm rate schedules. Indeed, in the reopened hearing, the three customer companies which opposed the original gas purchase contracts did not renew their opposition in the face of Texas Eastern's revised proposal involving purchase of the Rayne Field leases. It would be contrary to the public interest to deny the means for meeting this consumer demand without strong and compelling reasons—reasons which, in our judgment, are lacking in this case.

Further from the point of view of price, Texas Eastern adduced evidence to show that its unit cost of producing the Rayne Field gas will be less than the initial price for gas of 22.6 cents per Mcf under the original sales contracts with the producers. Texas Eastern's cost of producing the gas attributable to the working interests in the leases to be purchased from Continental, *et al.*, exclusive of return and related taxes, would be

3720

approximately 17.15 cents per Mcf, according to this evidence, At an assumed 6¾ percent rate of return plus re-

lated taxes,[8] the average cost to Texas Eastern of such gas would be 19.45 cents per Mcf. Further, employing Texas Eastern's estimate of 22.6 cents per Mcf as the maximum amount it would have to pay for royalty and minority interest gas, Texas Eastern's average cost of producing the Rayne Field gas would be 20.59 cents per Mcf, which is 2.01 cents per Mcf less than the initial price the producers originally proposed.

It is unsound to unqualifiedly characterize this 2.01 cents differential as a "saving" to Texas Eastern over the price for the gas under the original gas purchase contracts with the producers, since there is no basis for assuming that we would have certificated the producer sales at the initial price previously proposed. There is no question, however, but that, as stated above, the gas produced from the Rayne Field leases will be available at a cost of at least 2.01 cents per Mcf less than the initial price under the producer contracts; and the difference will be even more favorable to Texas Eastern if, as is reasonable to assume, the reserves are greater than presently anticipated.

Furthermore, the price Texas Eastern will pay for the Rayne Field leases is fixed for all production from this field, and is not subject to the annual escalations and indeterminate price increases provided for in the gas purchase contracts. The contracts provided for a fixed price escalation of 4 mills per Mcf on November 1 of each year resulting in a terminal contract price of 31.5 cents per Mcf and an average price of 26.6 cents per Mcf. The contract also prescribed redeterminations at the the end of each five-year contract period.[9]

---

[8] The company's computations were based on this figure and our use of it here is not to be interpreted as approval of this rate of return or claimed taxes for rate-making purposes. If the figure were reduced, the cost for this gas would be reduced also.

[9] Here too, it cannot be unqualifiedly assumed that we would have allowed such increased rates to become effective.

(3720)

The public will otherwise benefit from Texas Eastern's acquiring these leases instead of purchasing the gas under the producer sales contracts. For example, Texas Eastern will acquire control over the rate of production, and the minimum take or pay for provisions of the gas purchase contracts will be eliminated, thereby increasing the flexibility of the company's overall pipeline operations. Further, since the purchase of the leases is not a contract to purchase gas, the price paid for the leases cannot have a disruptive effect on area prices by triggering favored nation or price redetermination clauses in Texas Eastern's or any other pipeline company's contracts. Other benefits also exist.

3721

We find no objections to Texas Eastern's acquisition of the Rayne Field leases of such materiality as to offset the public benefit thereof and justify denial of Texas Eastern's project in this proceeding. Needless to say, a large number of natural-gas companies rely to a considerable extent for their supplies of gas on company-owned reserves, and the manner in which Texas Eastern's arrangements for the purchase of the leases were consummated is not unique in the gas and oil business, Texas Eastern's primary reason for handling the arrangements through an intermediary corporation, Louisiana Gas Corporation, was so it would not have any liability for the amount of the notes on its books. There was no evidence or implication that the negotiations leading to the lease purchase and sale agreements were anything but arm's-length and we find that they were arrived at on the basis of arm'-length bargaining. Weighing together all the elements of the public convenience and necessity, we find that the facts of this case justify the issuance of a certificate authorizing the modified project proposed herein by Texas Eastern, and that the objections of the New York Commission should be denied.

Economic feasibility.—Texas Eastern supported the feasibility of its project at the initial hearing by evidence showing estimated rates of return to the company for the first three years of service after the proposed facilities are constructed, assuming that the facilities would be in operation on September 1, 1958. Although Texas Eastern's computations show rates of return of 4.91 percent, 4.85 percent and 4.56 percent for the years 1959, 1960 and 1961, respectively, on a systemwide basis, these rates of return relate not solely to the facilities proposed in the subject dockets but rather to the entire system, including the additions proposed herein. The $49,088,000 investment in pipeline facilities proposed herein are a relatively small part of Texas Eastern's plant investment of $740,106,000 at the end of 1958, and would not of themselves cause a disproportionate reduction in the overall system rate of return. Texas Eastern also adduced evidence indicating that if the proposed rates in its rate increase application, Docket No. G-12706, were applied to the entire system sales, including those proposed herein the resulting rates of return would be 6.43 percent, 6.41 percent and 6.13 percent for the years 1959, 1960 and 1961. On the evidence of record, we conclude that the modified project is economically feasible, although this conclusion is not to be interpreted as approval of the rates proposed by Texas Eastern in Docket No. G-12706.

3722

Other matters.—In the light of the foregoing, all portions of the presiding examiner's decision issued April 15, 1958, relating to the certificate applications of Continental, Marr, Sun and General Crude, except for the findings respecting gas supply, are moot and should not be adopted by the Commission; otherwise the said decision of the examiner as herein modified should be adopted by the Commission. Likewise, the exceptions, appeals, motions and requests herein, relating to the aforesaid portions of the

examiner's decision and to the said certificate applications, are also moot and all such should be dismissed. For the reasons hereinabove stated, we shall deny the request of the New York Public Service Commission that these proceedings be remanded to the examiner for further evidence.

Continental filed a notice of withdrawal of its application for a certificate, conditioned upon the Commission's granting a certificate to Texas Eastern as applied for in Texas Eastern's amended and supplemented application. The notice recited that Continental had executed and delivered a contract of sale to Texas Eastern wherein Continental agreed to assign its leasehold rights in the leases in the Rayne Field formerly dedicated to the gas purchase contract subject to the receipt by Texas Eastern of a certificate which would nullify the gas [illegible]chase contract. In view of the certification herein of Texas Eastern's modified project, Continental should be permitted to withdraw its certificate application in Docket No. G-12432.

The Commission further finds:

(1) Texas Eastern Transmission Corporation is a Delaware corporation having its principal place of business in Shreveport, Louisiana, and is a "natural-gas company" within the meaning of the Natural Gas Act.

(2) The modified facilties proposed to be constructed and operated by Texas Eastern, as described hereinabove, in the record in this case, and in the company's applications, as amended, are to be used in the transportation and sale of natural gas in interstate commerce for resale, subject to the jurisdiction of the Commission; and the construction and operation thereof, and the sales of gas proposed by Texas Eastern by means thereof, are subject to subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Conformable to the authorization granted herein, Texas Eastern is able and willing properly to do the acts

and perform the service referred to in paragraph (2) above, and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation by Texas Eastern of the facilities and the rendition of the sales referred to in paragraph (2) above is required by the public convenience and necessity, and a certificate of public convenience and necessity thereof should be issued as hereinafter ordered and conditioned.

(5) The public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of the Commission's regulations under the Natural Gas Act should attach to the certificate hereinafter issued to Texas Eastern and to the exercise of the rights granted thereunder, and that the time within which construction of the facilities authorized by this order shall be completed should be fixed at six months from the date of issuance of this opinion.

(6) The presiding examiner's initial decision issued herein on April 15, 1958, as hereinabove modified, should be adopted by the Commission. All arguments, objections and exceptions not hereinabove discussed have been considered but are without substantial support in fact or reasonable basis in law and should be denied.

The Commission orders:

(A) A certificate of public convenience and necessity is hereby issued authorizing Texas Eastern Transmission Corporation to construct and operate the facilities proposed in the applications filed in Docket Nos. G-12446 and G-12447 herein, as amended and modified; and to sell and deliver to existing customers the additional volumes of

gas proposed in these proceedings in the maximum amount of 101,660 Mcf per day (14.73 psia), as follows:

Customer	*Mcf per day*
Algonquin Gas Transmission Company	10,200
The Columbia Gas System Companies	25,807
The Consolidated Natural Gas Companies	40,393
Equitable Gas Company	14,280
New Jersey Natural Gas Company	5,100
United Natural Gas Company	1,632
Elizabethtown Consolidated Gas Company	1,121
Illinois Electric & Gas Company	1,020
Village of Norris City, Illinois	102
City of Somerset, Kentucky	1,530
Tennessee Gas Company	474

(B) Permission is hereby granted to Continental Oil Company to withdraw its certificate application in Docket No. G-12432.

3724

(C) The general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificate granted herein and to the exercise of the rights granted thereunder.

(D) The time within the facilities hereby authorized shall be constructed and placed in actual operation is fixed at six months from the date of issuance of this opinion.

(E) The presiding examiner's initial decision issued herein on April 15, 1958, is hereby modified as hereinabove set forth, and as so modified is adopted by the Commission, to constitute with this opinion the Commission's decision in these proceedings. Except to the extent hereinabove granted, the exceptions to that decision and the other requests still before us in these proceedings are hereby de-

nied; and the matters and issues hereinabove found to be moot are hereby dismissed.

By the Commission.

/s/ Joseph H. Gutride,
Secretary.

3725

Docketed July 23, 1959

BEFORE THE

FEDERAL POWER COMMISSION

In the Matters of	Docket Nos.
Texas Eastern Transmission Corporation	G-12446
Texas Eastern Transmission Corporation (formerly Texas Eastern Penn-Jersey Transmission Corporation)	G-12447
Continental Oil Company	G-12432

3726

Application for Rehearing of Opinion 322

* * * * * * * * * *

On June 22, 1959, the Supreme Court of the United States held that purchases of natural gas by Tennessee Gas Transmission Company at initial prices of 22.4c per Mcf were out of line and, not having been justified by demonstration or producer need, were, accordingly, not in the public interest and unlawful. *Inter alia,* the Court observed that the availability of Section 5 proceedings to establish the proper price level ultimately, afforded no substitute for the requisite instant producer demonstration of the propriety of his initial price—but did provide the means of

(3726)

perpetually keeping proper initial certification in line price-wise*

On June 23, this Commission unconditionally certificated a project which, in its practical effect on Texas Eastern

3727

and ultimate consumers served through its facilities, is precisely the same as though that company had purchased gas at a totally unjustified 22.9 per Mcf price.* coupled with a perpetual guarantee against any future Section 5 adjustment! The explanation for the incorrect decision in this proceeding may lie solely in the fact that at the time Opinion 322 was written the Commission had not had the benefit of guidance of the Supreme Court's decision.

In any event, the certification is erroneous, improper and unlawful and must be rescinded.

ARGUMENT

I.

Opinion 322 Correctly Holds a Pipeline Project Depending on Indirect Gas Purchases Subject to the Same Standards of Public Convenience and Necessity as One Relying on Comparable Direct Purchases.

The Commission does not appear to have been led astray by the fact that the project before it involves a transfer of gas through acquisition of leases rather than through the more customary device of direct gas sale and purchase. Opinion 322 makes it perfectly clear that the determination of public convenience and necessity in respect of such a project is essentially no different from the same deter-

* *Atlantic Refining Co., et al. v Pub. Serv. Comm. of New York, et al.,* 27 Law Week 4460 (June 22, 1959).

* 20.59c per Mcf "base" cost of acquisition and production plus 2.3c per Mcf tax liability, rounded to 22.9c per Mcf.

mination in respect of a project depending on ordinary gas purchases.

3728

For example, although the Commission correctly observes that "Texas Eastern has not filed an application for a certificate authorizing the acquisition of the Rayne Field leases and we have no authority to issue such a certificate" (pp. 5-6), Opinion 322 quickly removes any incorrect inferences that might be drawn from this observation. It clearly states that the "basic question" for the Commission's decision in this proceeding "is whether Texas Eastern's project . . . *including reliance on Texas Eastern's acquisition of the Rayne Field leases . . . is required by public convenience and necessity and otherwise meets the requirements of Section 7(e) of the Act*" (p. 1, emphasis supplied). Obviously the answer to that question can be no different whether Texas Eastern's project includes reliance on its acquisition of Rayne Field gas through leases, comparable direct sales or any other means. Indeed, the statement of the question itself puts to rest any assumption that the Commission's lack of authority over gas lease acquisitions as such, would prevent its summary rejection of a Texas Eastern project relying on acquisition of the Rayne Field leases at say $281,065,000 rather than at the present proposed figure of $181,065.000.

We approve the Commission's approach to the problem of gas transfers through the acquisition of leaseholds. We agree that public convenience and necessity is not concerned with the form of gas transfers but only with whether the project, as tendered, is in the public interest, A project which

3729.

would not be in the public interest if the result of a direct gas purchase, can be no more so if the product of some other arrangement.

(3729)

II.

EVEN UNDER PRE-CATCO STANDARDS COMPARISON OF A PROPOSED PROJECT WITH SOME OTHER UNCERTIFIED PROJECT IS IRRELEVANT TO THE DETERMINATION OF PUBLIC CONVENIENCE AND NECESSITY.

How ever, although the issue is no longer important, we do feel compelled to put on record our objection to one aspect of the Commission's decision—its reliance, in considering public convenience and necessity, upon the fact that the present proposal represents an improvement, in terms of cost to Texas Eastern and other features, over the superseded proposals tendered for its authorization in 1957 (pp. 8-10).

The practice of justifying a proposed price by showing it is lower than some other price which might have been asked or formerly was asked, but which itself has never been shown to be required by public convenience and necessity, is so thoroughly inimical to the public interest as to be

3730

forbidden by the Natural Gas Act.* We can imagine no more efficient deterrent to responsible initial pricing practices by natural gas companies than encouraging belief that the key to unconditional certification lies in demand-

* For reasons that are obvious, the Commission has expressly and repeatedly disavowed any intimation that it is here finding, or would or could have found, the 1957 proposals to be required by public convenience and necessity:

> "It is unsound to unqualifiedly characterize this 2.01 cents differential as a 'saving' to Texas Eastern over the price for the gas under the original gas purchase contracts with the producers, *since there is no basis for assuming that we would have certificated the producer sales at the initial price previously proposed*" (p. 9; emphasis supplied).

> "Here too, it cannot be unqualifiedly assumed that we would have allowed such increased rates to become effective" (p. 9, ftn. 9).

ing prices even more exorbitant than those for which authorization is ultimately sought.

Moreover, although we can understand the Commission's enthusiasm for any *reduction* in price achieved through the operation of "arm's-length negotiation," we fear it may have overlooked the fact that ultimate consumers have been made to pay very dearly for the reduction achieved here—by sacrifice of future adjustment of the producer's price through Section 5 proceedings. This significant offset to Texas Eastern's "savings" has not been considered worthy of mention in Opinion 322. Yet Section 5 proceedings, for all their inefficiences and delays are consumers' sole assurance of ultimately

3731

obtaining just and reasonable producer charges. That assurance may not be lightly traded away without good and sufficient consideration.

III.

Texas Eastern's Proposed Project May Not Be Certificated Because A Comparable Direct Gas Purchase Could Not Be Authorized On The Instant Record.

As the Commission itself has tacitly acknowledged the "basic question" posed by Opinion 322 (i.e., whether Texas Eastern's project, including reliance on its acquisition of the Rayne Field leases, is required by public convenience and necessity) can be answered no differently than if Texas Eastern's project relied on some other form of gas acquisition at the same price and on comparable terms. Therefore, the answer to that question is now entirely dependent on whether a comparable direct gas purchase by Texas Eastern at a cost of 22.9c per Mcf could be unconditionally certified on this record under the principles established by the Supreme Court's CATCO decision. Manifestly, it could not.

(3731)

The present cost to Texas Eastern of acquiring and producing the Rayne Field gas (22.9c per Mcf) is even higher than the 22.4c found unlawful for purchases by Tennessee. It is nearly 65% higher than the maximum purchase price presently being paid by Texas Eastern in Louisiana. It is not merely subject to delay in adjustment to a just and reasonable level;

3732

it is completely immune to such adjustment.

The record provides an adequate explanation for a portion of that cost—the portion to be incurred by Texas Eastern as an incident to its own production of the gas. It provides no explanation whatever for the bulk of the cost—i.e., the amount to be received by the producers—except as the product of arm's-length negotiation. We do not question the presence of unique technical advantages to Texas Eastern under the present transaction. However, the relation of those advantages to the $181,065,000 price to be paid by Texas Eastern to the producers has not been established by the evidence—except, again, as the product of arm's-length negotiation. Such evidence, we respectfully submit, is no longer a satisfactory explanation for a price of this magnitude even if subject to Section 5 revision. It is grossly inadequate when that protection has been forfeited.

If indirect natural gas purchases (through pipeline acquisitions of leases) could be made on records which would be inadequate to support comparable direct purchases at the same price, the Supreme Court's CATCO decision would become a dead letter before the ink has had a chance to dry on its pages. We are certain that result will not be permitted to come about. Decisions of the Supreme Court may not be taken so lightly or circumvented so easily. The Commission has now had an opportunity,

lacking on June 23, to give the Supreme Court's decision the thoughtful examination and attention it requires. It remains only for the Commission to apply the Court's reasoning and principles to the instant proceeding.

3733

CONCLUSION

The record in the proceeding is utterly devoid of proof that Texas Eastern's project, depending on acquisition of the Rayne Field leases at $181,065,000 and resulting in a cost of production to it of 22.9c per Mcf, is required by the present or future public convenience and necessity. The only evidence in support of the $181,065,000 payment is testimony as to its arm's-length negotiation. Inasmuch as that evidence would be inadequate to sustain unconditional certification of a comparable direct sale and purchase by Texas Eastern at 22.9c per Mcf, it is equally inadequate to sustain unconditional certification of a project which would subject the purchaser to an identical burden.

In our initial brief filed herein on April 17, 1959, we requested the Commission to remand the proceeding to the Presiding Examiner to ascertain the price, for the acquisition of the Rayne Field leaseholds, which would warrant the determination that public convenience and necessity requires authorization of Texas Eastern's project. In Opinion 322 the Commission rejected that request on the ground that "the record in this case amply supports the conclusion that the elements of public convenince and necessity are satisfied by Texas Eastern's project "without such a determination (p. 5). Presently applicable considerations, however, show that the record does not support the Commission's conclusion, amply or at all.

3734

We have earnestly endeavored to evolve some alternative lawful disposition for this proceeding. Were it possible to

assign a monetary value to loss of consumers' rights to just and reasonable producer charges, we would request the Commission to locate an appropriate initial per Mcf price for a comparable direct sale of Rayne Field gas (using Commissioner Connole's "dominant prevailing price method" but excluding consideration of the CATCO sales and others subsequent to their execution at equal or higher prices) and to translate that price into a lump sum, then deduct from that figure the costs which will be incurred by Texas Eastern as a result of its own production of the gas and an additional amount to compensate consumers for loss of Section 5 protection and, on that basis, to determine an appropriate payment for Texas Eastern's acquisition of the Rayne Field leases. While the mechanics of finding an appropriate initial price would not present a difficult problem and the cost to Texas Eastern of producing the gas itself could be derived from this record, we are, unfortunately, unable even to undertake an estimate of the value of the consumer's sacrifice of their rights to just and reasonable producer charges—and doubt that the Commission is either.

Therefore, we are compelled to repeat our original request and to ask the Commission to reconsider its denial in

3735

the light of the present status of the law.

Respectfully submitted,

Dated: July 22, 1969

Public Service Commission of the State of New York

By Kent H. Brown
Counsel
55 Elk Street
Albany 1, New York

Barbara M. Suchow
Of Counsel

3736

State of New York }
County of New York } ss:

Barbara M. Suchow, being duly sworn, deposes and says she is Assistant Counsel to the Public Service Commission of the State of New York; that she has prepared and is authorized to execute and file the foregoing document; that she knows the contents thereof; and that all statements and matters set forth therein are true and correct to the best of her knowledge, information and belief.

Barbara M. Suchow

Subscribed and sworn to before me this 22nd day of July, 1959.

Margaret W. Raichert

Notary Public, State of New York
No. 41-3197400—Queens Co.

Term Expires March 30, 1961

3737—3739

Certificate of Service

• • • • • • • • • •

3740

(Docketed Aug. 21, 1959)

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Jerome K. Kuykendall, Chairman, William R. Connole, and John B. Hussey.

In the Matters of	Docket Nos.
Texas Eastern Transmission Corporation	G-12446
Texas Eastern Transmission Corporation (formerly Texas Eastern Penn-Jersey Transmission Corporation)	G-12447
Continental Oil Company	G-12432

Order Denying Application for Rehearing

(Issued August 21, 1959)

On July 23, 1959, the Public Service Commission of the State of New York (New York Commission) filed an application for rehearing of the Commission's Opinion No. 322 and accompanying order issued June 23, 1959, granting a certificate of public convenience and necessity to Texas Eastern Transmission Corporation (Texas Eastern) under subsection (c) and (e) of Section 7 of the Natural Gas Act (Act) authorizing the construction and operation of certain facilities and the rendition of the sales of natural gas to customers as set forth in that opinion.

We have considered the assignments of error and grounds for rehearing set forth in the New York Commission's application for rehearing, and have reconsidered our Opinion No. 322 and accompanying order in view of the Supreme Court's *Catco* decision (*Atlantic Refining Co.* v. *Public Service Commission of New York,* 79 Sup. Ct. 1246, June 22, 1959), and the decision of the Court of Appeals

for the Third Circuit in the *Transco* case (*United Gas Improvement Co.* v. *F.P.C.*, Nos. 12797 and 12805, —— F. 2d ——, (August 4, 1959), and we can find no reason for granting rehearing or disturbing the original opinion and order.

The Commission finds:

The assignments of errors and grounds for hearing set forth in the above-described application for rehearing filed herein by the New York Commission present no facts or principles of law which were not considered by the Commission when it issued its Opinion No. 322 and accompanying order on June 19, 1959, or which having now been considered warrant any change or modification of the said opinion and order.

3741

The Commission orders:

The application for hearing filed by the Public Service Commission of the State of New York on July 23, 1959, in the above-entitled proceeding, is hereby denied.

By the Commission: Commissioner Connole dissenting, filed a separate statement.

MICHAEL J. FARRELL,
Acting Secretary.

3742

In the Matters of
Texas Eastern Transmission Corporation, et al.

Docket No. G-12446, et al.

(Issued August 21, 1959)

CONNOLE, Commissioner, *dissenting:*

Opinion No. 322 in this proceeding approves the acquisition of natural gas for resale in interstate commerce by a pipeline company under conditions resulting in a cost of produced gas of 22.89c per Mcf. A proposal, such as this, "requires a most careful scrutiny and responsible reaction ***." *The Atlantic Refining Co., et al.* v. *P.S.C. of N.Y.*, 360 U. S. 378, ————. Clearly, the responsible reaction contemplated by the Supreme Court amounts to more than an announcement of the conclusion which the Commission sets out to determine.

In this case the need for a responsible reaction has been made more abundantly obvious by the mounting resistance to increased prices at the consumer end of Texas Eastern's pipeline and the increasingly inhibiting effect of competition from other fuels. This competition, of course, affects the marginal sale, the loss of which exerts a tremendous leverage on the rates of less price-sensitive sales.[1]

Against this background the approval of a cost of production for natural gas at a level at high as 22.89¢ per Mcf, including taxes, should only be forthcoming if the Commission is certain that such a price level is required by the public convenience and necessity or is just and reasonable within the meaning of Sections 4 or 5 of the Act.

The reasons advanced in Opinion 322 in support of the

[1] Algonquin Gas Transmission Company, for example, has recently filed a $4,061,000 or 12% rate increase. This directly affects 25 wholesale customers in one of the most price sensitive fuel markets in the nation. Algonquin is a wholesale customer of Texas Eastern.

conclusion that the proposel advanced by Texas Eastern is required by the public convenience and necessity are intended to explain why so high a cost is justified even though it is higher than only the very highest and smallest fraction of new contracts made in the area and even though

3743

the nature of the transactions permanently removes that cost from regulatory review and virtually commits us to allowing it as a reasonable operating expense in any rate making proceeding. There can be no question that elimination of take-or-pay-for clauses, the elimination of price escalations or indeterminate price increases and the increasing flexibility in the pipeline's operations all are plus factors. Indeed, they would be controlling in my judgment were it not for the more pervading consideration that no matter how it is disguised, the approval of this transaction for all practical purposes (if the gas-buying business is anything, it is a practical business) will be considered as approval of a cost or a price of 22.89¢.

It is immaterial, it seems to me, that the cost of production might be lower than 22.89¢ ultimately. This fortuitous circumstance would be a consummation devoutly to be wished indeed. The important thing, however, is that we have approved the transaction on the assumption that it could be as high as 22.89¢. While it may be true that "the price paid for the leases cannot have a disruptive effect on area price by triggering favored-nation or price redetermination clauses," it will have at least an equally disruptive effect on area prices by putting another solid plank under the floor for gas prices in South Louisiana that is growing discouragingly firmer with each decision involving prices in that area. In other words, this transaction will just as certainly operate to fix the cost of purchased gas in South Louisiana for initial contracts as it would be if the original proposal made by the producers and Texas East-

ern were approved. Perhaps the rate level is not identical but the effect of the Commission's approval of this rate level is the same. After all, the approval of the cost of produced gas at 22.89¢ does not differ materially from the approval of a cost of purchased gas at 28.89¢.

If there is any doubt of this conclusion, consider the context in which the application was made.

We are asked specifically to approve not only the construction and the operation of the facilities required and the sales proposed, but, indeed, the cost of acquiring the reserves as well. The care and attention given to the amount of moneys that will change hands in this transaction, the resultant estimated cost of produced gas, and, indeed, the approval of the capitalization of so much of the cost price as would be capitalized can be interpreted logically only as the approval of a proposed transaction contemplating a cost of purchased gas of 22.89¢.

3744

Applying to this transaction, then, the principles which the Supreme Court has so plainly directed us to apply and looking at the record for evidence whether the price is required by the public convenience and necessity, I am unable to conclude that this transaction, desirable though it may be in some particulars, can be said to be required by the public convenience and necessity under the terms and under the conditions on which it is proposed to us. It must be remembered that even in circumstances where the Commission has issued certificates of public convenience and necessity authorizing the sales of gas at a price as high or higher than approved here, we still have some handle on the matter through the operation of Section 5 of the Act. Even this small consolation is absent in this case. It would be far more desirable, in my judgment, for the applicants here to submit their proposal on the same basis as other applicants than to attempt to circumvent

regulation and then to ask for specific Commission approval of the result. Indeed, it would be better for the Commission to say nothing at all about prices and approve only the construction, operation and sale and to leave the question of price for determination after the principles of pricing have become firm.

The simple truth is that by the device of this sale, producers have succeeded in obtaining the same cash compensation in the long run as they would have obtained under the original transaction, Texas Eastern has committed itself to a probable cost of 22.89¢ per Mcf and we have specifically approved the whole thing—permanently—with no possibility that the Commission will ever be able to review it. I do not believe it is in the public interest to permit the uncomfortable thrust of alleged insatiable demand to goad us into approving any such permanent circumvention of the Natural Gas Act. Under these conditions, I can see no obstacle to any pipeline or any group of producers entering into such a transaction. Then, as here, all the advantages will be trotted before us in justification of the transaction. But then, just as certainly as here, we would be abdicating our responsibility to approve the proposal unless we knew whether the resultant cost is within the bounds either of reasonableness (since it would be a permanent cost) or at least of public convenience and necessity. I do not believe we ought to do anything that would make possible such a circumvention of our rate making responsibilities under the Act.

For these reasons, I am unable to agree with this order which denies reconsideration of the earlier Opinion 322.

William R. Connole,
Commissioner

1802

Washington, D. C.
Monday, October 23, 1961

* * * * * * * * * *

1805

PROCEEDINGS

Presiding Examiner: Gentlemen, the hearing will come to order.

* * * * * * * * * *

By an order issued on July 14, 1961, the Commission reopened the record in this proceeding to afford Texas Eastern the opportunity to make the showing contemplated by the Circuit Court of Appeals. In its July 14, 1961 order, the Commission defined but did not necessarily limit the issues and procedures to be followed.

* * * * * * * * * *

1807

E. A. Olson, Jr.

was called as a witness, being first duly sworn, and testified as follows:

Direct Examination

By Mr. Deakins:

Q. Dr. Olson, would you state your name, address, and position of employment for the record, please? A. My name is E. A. Olson, Jr. My address is 2625

1808

Daniels Avenue, Dallas, Texas. I am a vice president of the firm of DeGolyer and MacNaughton, Dallas, Texas.

Q. What is the business of the firm of DeGolyer and

MacNaughton? A. The firm of DeGolyer and MacNaughton is a corporation and has as its principal business the estimation of petroleum reserves, the appraisal of the availability of such reserves and their value, the planning and, in certain cases, the conduct of geological exploration, and petroleum exploration for many individuals and companies. A part of the work done by our firm is in connection with the appraisal of oil and gas properties which are pledged as collateral for loans obtained from banks, insurance companies, and other lending agencies. Additional work by the firm includes the preparation of estimates of the oil and gas reserves and the availability of these reserves for submission to the Federal Power Commission and Securities and Exchange Commission.

* * * * * * * * * * *

By Mr. Deakins:

Q. Please state your educational background and experience in the industry. A. I hold a Bachelor of Science Degree in Petroleum Engineering from the Agricultural and Mechanical College of

1809

Texas. I have been employed in various phases of the oil business during the past 18 years, with the exception of three years of active duty in the Combat Engineer Corps of the United States Army during World War II. After my release from the Army I was employed by Texas Company and was placed in their reservoir engineering department in New Orleans, Louisiana. This work consisted of various phases of reservoir engineering and geology. I have remained in this department for 3½ years, after which time I joined the firm of DeGolyer and MacNaughton. I have been with this firm since 1949, and have worked primarily in the estimation of the extent, value, and avail-

(1809)

ability of oil and gas reserves, particularly in south Louisiana.

I am a Registered Professional Engineer in the States of Louisiana and Texas, and a member of the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical and Petroleum Engineers. I have previously testified before the Federal Power Commission in Dockets Nos. G-12446, G-15394, G-18338, and G-11024.

Mr. Deakins: Mr. Examiner, I would like to have marked for the purpose of identification an exhibit entitled "Estimated Reserves and Availability of Residue Gas, Condensate, and Plant Liquids of Texas Eastern Transmission Corporation in Rayne Field, Acadia Parish, Louisiana as of January 1, 1961."

Mr. Examiner, we have marked this exhibit as X-2 in ac-

1810

cordance with some requests of the staff of the Commission. We have furnished that information to them. If that is agreeable with the Examiner, we can continue with those identifications.

Presiding Examiner: Are those numbers carried throughout the exhibit?

Mr. Deakins: Yes, on the pages. I might advise the Examiner of this fact: In the earlier phases of this proceeding the exhibits were numbered with Arabic numerals commencing with 1. We tried this case twice before and then when we came back we identified the exhibits as M-1, M-2, through M-14, as I recall it. It doesn't make a lot of difference to us. It would be a little easier for our presentation to call these X-2 and thereafter.

Mr. Lewnes: Mr. Examiner, the formal files indicate that the last formal exhibit in these proceedings was M-21.

Presiding Examiner: Off the record.

(Discussion off the record)

Presiding Examiner: Back on the record.
It will be marked X-2 for identification.

(Whereupon the document referred to was marked for identification as Exhibit X2.)

By Mr. Deakins:

Q. Handing you what has been marked for identification, for the purposes of identification, Exhibit X-2, please state

1811

whether you prepared part of that exhibit for presentation in evidence in this case. A. Yes, I have. Our firm was commissioned by Texas Eastern Transmission Corporation to prepare estimates of the gas condensate and plant liquids reserves in the Rayne field, Acadia Parish, Louisiana.

Q. Have you previously prepared an exhibit in connection with your earlier testimony in these proceedings? A. Yes, I prepared an estimate of the reserves of natural gas in the Rayne Field as of January 1, 1959, which was reduced to exhibit form and presented as Exhibit M-13 in these proceedings, and I also testified with reference to the reserves in the Rayne Field, as shown by that exhibit. And as a matter of fact, it was those reserves which the Commission found to be the reserves in the Rayne Field in the certificate which was issued previously.

Q. Since the preparation of Exhibit M-13, have you kept abreast of the development of the Rayne Field until the present time? A. I have.

Q. State what changes, if any, have occurred in the field since your exhibit of 1959 was prepared. A. During the period between 1959 and 1961 there have been four additional wells drilled, one prior to the time when Texas Eastern acquired the field in July, 1959, and three since

1812

that time. These wells have not materially changed the field in any respect. While data made available from these wells has resulted in certain alterations in our interpretations, the overall effect in terms of the total field reserves is negligible.

Q. Has the drilling of any of these wells resulted in proving up any additional reservoirs from your original exhibit? A. Yes, they have.

Q. Now referring you again to Exhibit X-2, please state what it is and whether you prepared any part of it, and if so, what part did you prepare?

A. That part of Exhibit X-2 which I prepared is the tabulation found on page 1, with the exception of the condensate and plant liquids reserves found on lines 28 and 29 of page 1. In addition to that tabulation I also prepared the map shown on pages 3 and 4 of that exhibit.

Q. State what that part of page 1 of Exhibit 2 which you prepared purports to show. A. The tabulation on page 1 of Exhibit X-2 shows the reserves of the Rayne Field by reservoirs involving all the basic data pertinent to these reserves as of January 1, 1961.

Q. Now what do pages 3 and 4 of that exhibit show? A. On pages 3 and 4 of Exhibit X-2 I have shown the productive limits of each proved reservoir in the field and

1813

the acreage which is dedicated to Texas Eastern. In this exhibit we have included two new reservoirs; namely, the Homeseekers D-2 and the Homeseekers D-4. These two reservoirs were not included in the original exhibit as of January 1, 1959.

Q. Have both of those reservoirs been tested? A. No, the Homeseekers D-2 reservoir has been tested and is now producing from two completions. However, the Home-

seekers D-4 sand has not been tested, but we feel that due to the similarity of the electric log characteristics and sand conditions existing in this reservoir, compared with the Homeseekers D-2 reservoir, that this sand should be considered as proved, and as a consequence I have included it in my exhibit.

Q. Of the dedicated reserves in the Rayne field you have shown on line 27 of page 2 of Exhibit M-13, 988,771 MMcf of natural gas. What comparable figure is shown in your Exhibit X-2 on page 1? A. I have shown on line 27 residue gas reserves under column M, the figure 924,678 MMcf, which compares to the figure 988,771 MMcf.

Q. How do you account for the difference in those two figures? A. The difference is accounted for almost entirely by the interim production of 65,396 MMcf.

1814

Q. What method did you use for estimating the gas reserves in the Rayne Field in 1959? A. The volumetric method.

Q. What method have you used in estimating the reserves as shown by Exhibit X-2? A. I used the same method.

Q. In using the volumetric method, what information did you use and what procedure did you follow in making these estimates? A. In estimating reserves by the volumetric method, structural and isopachous maps first were prepared for each proved reservoir in the field, and were based on all data available; namely, the electric and mico logs. All available core analyses were used to determine the average porosity and interstitial water percentages and permeabilities for each reservoir. In addition, electrical log calculations and charts showing a plot of permeability versus irreducible water were used in determining intersitial water percentages. Measured reservoir prssures and temperatures were used, and where such measurements were not available, temperature and pres-

sure gradient curves were constructed, using data that was available. Reservoir pressures in this field are abnormally high. However, this is a common characteristic for fields of this type in this area, and as a result it is expected that these fields generally will be produced by pres-

1815

sure depletion.

Assuming this field will be depleted through pressure depletion, I have arrived at a recoverable reserve by estimating a reasonable abandonment pressure.

Q. Referring you to page 1 of Exhibit X-2, I take it that the residue gas reserve of 924,678 MMcf is the total reserve available to Texas Eastern. Please state what the term "residue gas" means as you have used it here. A. The term "residue gas," as used in this exhibit, is that gas which is available for sale after having taken into account the combination of losses due to condensation in the reservoir, the extraction of separate or condensate and plant liquids.

Mr. Deakins: I now offer pages 1, 3, and 4 of Exhibit X-2.

Presiding Examiner: The offer will be taken under advisement until the completion of cross-examination of this witness.

Mr. Deakins: I tender the witness for cross-examination.

Mr. Lewnes: Mr. Examiner, I presume that we would proceed along the usual procedures in these proceedings where Texas Eastern would put on all of its witnesses, and at the presentation of its direct case we would make a statement as to whether we would cross-examine immediately or ask for a recess for cross. Consequently, we don't intend to cross-ex-

1816

amine this witness at this time.

* * * * * * * * * * *

Mr. Deakins: Mr. Marshall.

Dan L. Marshall

was called as a witness, being first duly sworn, and testified as follows:

Direct Examination

By Mr. Deakins:

Q. Please state your name and address. A. My name is Dan L. Marshall, and my address is 5625 Daniels Avenue, Dallas, Texas.

Q. By whom are you employed and in what capacity? A. I am a Vice President of the firm of DeGolyer and MacNaughton, and employed as a geological and petroleum engineer, having been so employed since June, 1948.

Q. Please state your professional education. A. I received my primary and high school education in the public schools of Louisiana. I was graduated from

1817

Louisiana State University in August, 1939 with a Bachelor of Science Degree in Petroleum Engineering.

Q. State whether you are a registered professional engineer and of what professional societies you are a member? A. I am a registered professional engineer in the States of Louisiana and Texas. I am a member of the National Society of Professional Engineers, the American Association of Petroleum Geologists, and the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers.

In 1946 and 1947 I was a member of the standing subcommittee on secondary recovery of the American Petro-

(1817)

leum Institute. In 1947 and 1948 I was a member of the production technology committee of the Petroleum Division of the American Institute of Mining and Metallurgical Engineers.

Q. What has been your employment during your adult life? A. In the summer of 1937, I was employed by the Shell Petroleum Corporation as a gauger in a tank farm terminal in Southwest Louisiana. Here my duties were concerned with the details of movement of crude oil from pipelines into tanks and from tanks into barges or ships. In the summer of 1938 I was again employed by Shell Oil Company, Inc., in Texas. My duties consisted of the details concerned with repair and maintenance of surface and subsurface equipment,

1818

assistance to the district exploitation engineer in preparing maps, geological cross-sections, the examinations of cuttings obtained from drilling wells, setting casing and completing wells. Upon graduation I was employed by The Texas Company producing department. Here my work covered practically all phases of drilling and production, including geological and petroleum engineering problems.

From January, 1943, until June 1948, I was in responsible charge under the division petroleum engineer of all company reservoir engineering work in the Louisiana division, which included the east Texas area, Louisiana, Arkansas, Mississippi, and the remainder of the southeastern United States. This work included the formulation of programs to accumulate basic data, interpretation of these data to provide estimates of reserves, and the availability of those reserves, appraisal of individual properties, design of producing programs for multiple-reservoir fields, and appraisal of the various operating methods for a given property or field.

In addition, considerable time was devoted to unitization programs and the operation of fieldwide or reservoir-wide units in connection with some form of cycling or pressure maintenance operation. In order to finalize certain of these programs it was necessary for me to appear on numerous occasions as a witness before the Louisiana Department of Conservation and the State Oil and Gas Board of Mississippi.

In June of 1948 I was employed by the firm of DeGolyer and MacNaughton. From that time to the present my work has dealt with problems in exploration for and exploitation of oil and gas, including appraisal of petroleum prospects, drilling techniques, production problems, estimates of reserves, appraisal of properties for value, both producing and potentially productive, management of properties, management of companies, company exploration and exploitation programs, and problems in gas storage.

The oil and gas properties that have been involved in the foregoing work are located in 13 of the 29 producing States of the United States. In addition, I have performed similar types of work on properties located in Canada, Mexico, Columbia, Brazil, France, Egypt, Saudi Arabia, and the Kuwait Neutral Zone.

During the time from June, 1948 to the present, however, the majority of my attention and work has been devoted to the Gulf Coast area. I have been familiar with the Rayne Field, Acadia Parish, Louisiana, from its discovery in 1953 through its development and production to date.

Q. Have you prepared an estimate of the availability of the reserves of residue gas, condensate, and plant liquids from the various reservoirs in the Rayne Field? A. I have.

Q. Handing you what has been marked for the purposes

1820

of identification as page 2 of X-2, would you please state what that is and by whom it was prepared?

A. That is an estimate of the reserves of residue gas, condensate, and plant liquids as of January 1, 1961, as shown at lines 28 and 29 on the first page of Exhibit 2, and as shown as estimates of annual production of residue gas, condensate, and plant liquids, and also in total, which was prepared by me.

Q. Please describe this exhibit. A. The exhibit bears a caption marked "Estimated Production" and is in columnar form. The first, column A, is a line number corresponding to the years shown in column B, commencing in 1961 and ending in 1989. The third column shows the quantities of residue gas available through each of those years, and the total in line 30. Column D is the estimate of condensate expressed in barrels, and column E shows the plant liquids expressed in barrels with totals of each shown at the bottom. Column F is self-explanatory.

Q. How did you determine the quantities of residue gas shown to be available in column C on page 2 of Exhibit X-2? A. In reaching these conclusions, studies were made of the volumetric and phase behavior of the reservoir fluids as shown by actual laboratory data, where available, and estimates for those reservoirs for which laboratory data were not avail-

1821

able. Where available, multi-point back pressure tests, and where not available, a succession of single-point back pressure tests were analyzed, using methods described in a publication by the Railroad Commission of Texas, entitled "Back Pressure Test for Natural Gas Wells, State of Texas." As a result of these studies it was possible to forecast the availability of residue gas from the various reservoirs in the Rayne Field during pressure depletion.

We were instructed by Texas Eastern Transmission Corporation to assume demand for residue gas from the Rayne Field at a rate of 51,100 MMcf per year for 13 years, and to maintain that rate by supplementing well capacity as needed, by anticipating the completion of additional wells during that period, thereafter estimating the production decline as capacity declines with pressure. Well capacities under these conditions are such that the Rayne Field will be depleted in the year 1889.

Q. Inasmuch as the condensate and plant liquids are related, will you please state how you reached the conclusion expressed in columns D and E of page 2 of Exhibit X-2? A. The attendant volumes of separator condensate and liquids to be produced with the estimated volumes of reservoir gas were obtained through a study of the volumetric and phase behavior of the reservoir fluids as laboratory data were available, and estimated for those reservoirs for which no laboratory data were available. The separator yields for the

1822

various reservoirs conform with actual separator yields. Estimates of plant liquids were based on extraction efficiencies used in plant design and adjusted for experience during the first 12 months of plant operation. The total condensate and plant liquids production, as shown on the second page of Exhibit X-2, agree with the estimated reserves shown on the first page of Exhibit X-2.

Q. In connection with your study of the Rayne Field were you asked by Texas Eastern to estimate as a part of the availability study the necessity for the drilling of additional wells in that field in order that Texas Eastern would be able to produce the total quantities of gas and liquids as shown on your exhibit? A. I was.

Q. As a result of this study did you determine whether

or not any additional wells would be required to be drilled? A. I did.

Q. How many? A. Two additional dual completions will be required in the year 1962, one side of each to be used to produce the Homeseekers D-2 sand, the other side of one to be used in the Nodosaria A South, and the other in the Homeseekers D-4 sand. In 1971, an additional well will be needed to be completed in the Nodosaria A. South and the Homeseekers E sands. In 1972, one additional well to be drilled or completed also in the

1823

Nodosaria A South and the Homeseekers E sands.

Q. Why do you determine it necessary for these wells to be drilled in the years you have indicated? A. In order to complete development of the field, in the first instance, two additional undrilled locations will be required to be drilled in order that Texas Eastern recover from the Homeseekers D-2 sand the gas which is dedicated to it. A completion in the Homeseekers D-4 sand will allow that sand to be brought into production immediately and the additional completion in the Nodosaria A South, while it is not immediately needed, will provide standby capacity as needed during the period from 1962 to 1971.

The aggregate capacity of all of the wells in the Rayne Field should be sufficient to meet the desired take from the field until 1972. By that time the pressure in the various reservoirs will have declined to the extent that it will have reduced the well capacity to the point where an additional two completions would be required by the end of 1971 to meet the desired daily take.

The reservoir pressures will continue to decline with production, and the resultant losses in well capacity will require two additional completions in 1972, as was stated in the answer to the previous question.

Q. From your knowledge and study of the Rayne Field

and your experience in south Louisiana, have you made an estimate

1824

of the number of work-overs of wells which will be required during the time shown on your exhibit and which will enable Texas Eastern to produce the quantities which you have estimated? A. I have.

Q. Please state what your estimate is with reference to that matter. A. In 1962, Nodosaria Unit 5, No. 1, must be reperforated to open the entire productive section. This well is now open in only 15 feet of the productive section, whereas several times that is available to production and should be opened. In 1963 it will be necessary to squeeze perforations now open in Nodosaria Unit 9, No. 1, in order to shut off water and reperforate in the remaining sand above the level at which water is now being produced.

In 1967, one well should be recompleted from the Klumpp D sand to the Homeseekers E sand to increase the deliverability of gas from that sand. In 1971, one well should be recompleted from the Klumpp D sand to the Klumpp E sand to bring the latter sand into production. In 1972, upon the depletion of the Homeseekers D-4 sand, recomplete that well in the Homeseekers E sand, again increasing the deliverability of gas from that sand.

Q. Were you asked to advise Texas Eastern with reference to the volumes of residue gas to be produced from each reservoir

1825

and the wellhead pressures of the various wells which have been drilled and will be drilled in the Rayne Field in order to determine when compression would be required and in what volume? A. I was. I gave them estimates of the annual volume of residue gas to be produced and the flowing wellhead pressure which would exist for wells producing from each reservoir on an annual basis.

Mr. Deakins: I now offer page 2 of Exhibit X-2 and tender the witness for cross-examination.

Presiding Examiner: Your offer will be taken under advisement.

* * * * * * * * * * *

1827

John P. Furman

was called as a witness, being first duly sworn, and testified as follows:

Direct Examination

By Mr. Deakins:

Q. Please state your name and address. A. My name is John P. Furman. My business address is 1523 L St., N.W, Washington, D. C.

Q. By whom are you employed and what is your position with that firm? A. I am employed by Foster Associates, Inc. I am general manager of the firm.

Q. How long have you been with Foster Associates and in what way have your duties with the firm prepared you to present the testimony you are to give in this proceeding? A. I have been a member of Foster Associates since July, 1956, and during this period I have participated actively in

1828

our research on current market prices and on regulatory actions in certificates and rate-making proceedings. I share with our Midcontinent manager responsibility for these research programs.

Q. What, briefly, has been your education? A. I received an AB Degree from Princeton University in 1942, an LLB Degree from Yale Law School in 1946, and an MA Degree in the field of Economics from American University in 1954.

Q. What experience have you had in the field of economics, apart from the experience you have gained as a member of Foster Associates? A. In 1946 I taught elementary economics at Yale University as a part-time assistant in instruction. From 1946 through 1948 I was employed as an economist by the Department of State in the industry branch of the Office of International Trade. From 1948 through June, 1956, I was an attorney-advisor in the Office of the Legal Adviser in the same department, and during the latter half of the period I was responsible under the general direction of the Assistant Legal Adviser for Economic Affairs for providing legal advice on problems arising in connection with foreign aid programs, including programs of economic assistance.

In 1959, I served as a consultant to the Draper Committee, which had the formal title of the President's Committee to

1829

Study the United States Military Assistance Program, and in that capacity I participated in the preparation of the committee's report on economic assistance programs and their administration.

Q. Is this your first appearance before this Commission? A. No. I appeared as a witness on behalf of Gulf Oil Corporation and Tidewater Oil Company in the Bastian Bay certificate proceeding, United Gas Pipe Line Company, et al., Docket Nos. CP60-36, et al., and presented both direct and surrebuttal testimony on natural gas prices.

Q. Have you appeared elsewhere as a witness? A. Yes, in 1960 I appeared as a witness for Tennessee Gas Transmission Company in a proceeding in the District Court for the 126th Judicial District of the State of Texas, and testified concerning problems relating to the determination of the current market value of gas in Texas for purposes of

(1829)

calculating the amount of tax due under the Texas severance beneficiary tax.

Q. On what subject have you been asked to testify in these proceedings? A. I have been asked to present information on field prices so that the acquisition cost to Texas Eastern of the Rayne Field gas can be compared with prevailing market prices for gas under long-term gas sales contracts.

Mr. Deakins: Mr. Examiner, I would like to ask that there

1830

be marked for the purpose of identification as Exhibit X-6 an exhibit entitled "Exhibit Accompanying Testimony of John P. Furman." The reason we are asking that this be marked out of order is that the other exhibits have been marked on various pages with serial numbers following the exhibits which have been offered here this morning and it won't disturb anything in the proceeding.

Presiding Examiner: It will be marked X-6 for identification.

(Whereupon the Document Referred to was marked for identification as exhibit X-6.)

By Mr. Deakins:

Q. Referring you now to Exhibit X-6, Mr. Furman, will you state whether the data on which you rely are set forth in that exhibit? A. Yes, sir.

Q. Was this exhibit prepared by you or under your general supervision and direction? A. It was.

Q. Please state how this exhibit is organized. A. The first seven schedules deal with prices paid for gas in south Louisiana by interstate pipelines under long-term contracts dated between January 1, 1958, and June 30, 1959. The next schedule, Schedule 8, summarizes prices paid under

Long-term contracts dated after July 1, 1959. The final sched-

1831

ule, schedule 9, lists sales which have been permanently certificated by the Commission where the average base price called for by the contract was 20c or more.

Q. This outline of your exhibit indicates that you will give primary attention to the period January 1, 1958, through June 30, 1959. Why have you selected this time period? A. Texas Eastern instructed me to give primary attention to market prices prevailing during the general period of time that the lease-purchase agreement through which Texas Eastern acquired the interest of the majority working interest in Rayne Field was negotiated and consummated.

The lease-purchase agreement was dated December 4, 1958. I understand that the consummation of the agreement was contingent on the completion of a number of additional steps and that the transaction was finally concluded in July, 1959.

Another consideration is that the time period should be long enough to contain a substantial number of transactions. It was my conclusion that it would be appropriate to use a period of 18 months, beginning roughly one year prior to the conclusion of the lease-purchase agreement.

Q. What contracts dated between January 1, 1958 and June 30, 1959 are covered by your analysis? A. The analysis covers all sales in south Louisiana, including off-shore areas to interstate pipelines under long-term contracts which I have defined as contracts with a

1832

term of 15 years or longer, including contracts for the life of the lease. We have identified as coming within this definition 216 contracts which have been filed by the seller

with the Federal Power Commission either as rate schedules or in six cases with the seller's application for a certificate of public convenience and necessity. Since the primary concern is with the alternatives which were available to Texas Eastern in the south Louisiana market at or around the end of 1958, this analysis of market prices as set forth in Schedules 1 through 8 is not concerned with whether the sales in question have been permanently certificated by the Federal Power Commission.

I will deal separately with permanently certificated sales at a later point in my testimony.

Q. What information concerning these contracts is shown on your Schedule1? A. In addition to identifying the contracts by purchaser filing company, rate schedule number, and date of contract, Schedule 1 shows the field and parish, the term of the contract, the point of delivery, what types of price adjustment clauses the contract contains, whether the contract contains a take or pay clause, and the maximum pressure at which the seller may have to make deliveries in order for the gas to enter the buyer's line.

Column K shows the volume of annual deliveries under the

1833

contracts. Provided the date of initial delivery was prior to January 1, 1960, the annual volume figure in column K is taken from the purchaser's form 2 report to the Federal Power Commission. Otherwise, the annual volume figure is based on the first month's volume shown in the seller's estimated billing statement. The remaining columns contain price information.

Q. Before you discuss the information on these remaining columns, will you state whether your exhibit contains additional information on the quality specifications in these contracts? A. It does, in Schedule 2, which is based on the 210 contracts filed as rate schedules. In south Lou-

isiana, the quality specifications in gas sales contracts are fairly standard, as Schedule 2 shows. Accordingly, I did not consider it necessary to include these specifications on a contract-by-contract basis in Schedule 1.

Q. Turn now to the price columns in Schedule 1. What prices did you show for each contract? A. Columns L through O show, respectively, initial base price, the average base price, the initial base price plus tax reimbursement payable by the buyer at the Louisiana tax rate which has been in effect since the end of 1958, and the average base price plus the same tax reimbursement.

Q. What do you mean by initial base price?

1834

A. I mean by initial base price the price provided in the the base price schedule which is applicable at the date of initial deliveries under the contract. It does not include adjustments which may be called for by other provisions of the contract on account of such factors as Btu content, sulphur content, or gathering. It should be noted that this initial base price is only a part of the price bargain between the parties to a contract because the initial base price is only a part of the base price schedule, and the contract usually contains other provisions which affect the price.

Q. What do you mean by the term "average base price"? A. By average base price I mean the average of the prices which will be paid in accordance with the base price schedule in the contract for all gas delivered during the term of the contract, assuming that deliveries are made at a uniform annual rate.

Q. How have you calculated this average base price? A. The average base price has been calculated by weighting the initial base price and each of the subsequent fixed prices by the length of the period for which each price is to be effected. Where the contract is for the life of the

reserves, it is assumed for the purpose of computing the average base price that the term is 20 years.

Q. Which of the prices shown on Schedule 1 do you consider to be the most significant for the purpose of this pro-

1835

ceeding? A. The Commission has stated in the order issued in this proceeding on July 14, 1961, that it plans to determine "whether the cost of the Rayne Field gas to Texas Eastern and its customers over the productive life of the field is out of line." This makes it clear that the Commission is interested in prices over a period of years. The initial base price, however, relates only to the gas delivered in the early years of the contract, except in the rare case in which the contract provides for no fixed step-ups. On the other hand, the average base price is an expression of the prices called for by the fixed price schedule of the contract over the term of the contract, and for this reason provides a better basis for comparing the cost of gas under a lease-purchase arrangement with prices paid under a sales contract.

Q. Does this mean that you will ignore initial base prices in your analysis? A. No, I have also included initial base prices in the analysis. In this connection I would like to point out that neither average base prices nor initial base prices reflect the effect of favored nation, redetermination or other indefinite pricing clauses. From the point of view of the seller, these clauses are very valuable components of the total price bargain.

Q. Up to this point you have not discussed tax reimburse-

1836

ment. Do you propose to use tax-inclusive prices? A. Yes, the prices shown for gas sold under the gas sales contracts with which the Rayne Field transaction is to be compared

should include an amount for tax reimbursement by the purchaser in cases where such reimbursement is required by the contracts. It is my understanding that in the past the Commission has uniformly permitted independent producers to file for and collect the amounts of tax reimbursement provided for by their contracts without suspension or refund obligation, except in cases where the constitutionality of the tax has been contested in the courts or where there is a question concerning the amount of tax reimbursement to which the producer is entitled. Accordingly, we have added to the initial base price shown in column L of Schedule 1 and the average base price shown in column M of Schedule 1 any tax reimbursement payable under the terms of the contract at the tax rate in effect since the end of 1958.

Q. Based on tax-inclusive prices shown on Schedule 1, what was the pattern of prices prevailing in the south Louisiana area in the period January 1, 1958 through June 30, 1959? A. To assist in answering this question, the prices shown in Schedule 1 have been distributed from highest to lowest with initial base prices plus tax reimbursements shown in Schedule 3 and average base prices plus tax reimbursement

shown in Schedule 4. Each of these schedules shows the number of contracts at each price, the number of contracts for which volume information is available, and the total volume at each price.

Q. What are the results of this analysis? A. The significant data are those which show the volumes of gas which were purchased at different price levels during this 18-month time period. Out of 212 contracts for which we have volume information, 93 provided for an initial base price plus tax reimbursement of more than 23c per Mcf. These contracts accounted for volumes totaling 253,000 MMcf,

or over 60% of the total volume of 404,000 MMcf. On the basis of volume, the median price was 23.55¢ per Mcf.

Q. What proportion of the total volume was acquired at initial base prices plus tax reimbursement of 20¢ per Mcf or more, and what proportion was acquired at prices below this level? A. Out of the total volume of 404,000 MMcf, 369,000 MMcf were acquired at 20¢ per Mcf or more, and the remaining 35,000 MMcf, or only 9%, were acquired at less than 20¢.

Q. If one assumes that on the average the reserves represented by long-term gas sales contracts are 20 times the annual delivery volumes that you have used, how large were the reserves acquired during this 18-month period at initial base prices plus tax reimbursement of less than 20¢ per Mcf?

A. On the basis of such an assumption, the data in Schedule 3 indicate that only 700,000 MMcf in reserves were acquired at initial base prices plus tax reimbursement of less than 20¢ per Mcf.

Q. What are the results, if one looks to average base prices plus tax reimbursement? A. More than half the contracts, or 110, provided for prices of 25¢ per Mcf or more. These contracts accounted for volumes totaling 315,000 MMcf, or over 75% of the total volume of 404,000 MMcf. The median price on the basis of volume was 25.90¢ per Mcf.

Q. What proportion of the total volume was acquired at average base prices plus tax reimbursement of 20¢ per Mcf or more, and what proportion was acquired at prices below this level? A. Out of the total volume of 404,000 MMcf, slightly more than 401,000 MMcf were acquired at average base prices plus tax reimbursement of 20¢ per Mcf or more, and only between 2,000 and 3,000 MMcf, or less than one per cent, were acquired at prices below 20¢ per Mcf.

Q. If one assumed again that on the average the reserves represented by these contracts are 20 times the annual delivery volume, how large were the reserves acquired during this 18-month time period at average base prices plus tax reimbursement of less than 20¢ per Mcf?

1839

A. On the basis of such an assumption the data in Schedule 4 indicate that less than 100,000 MMcf were acquired at prices below 20¢ per Mcf.

Q. Are there any other conclusions which should be drawn from the data presented in Schedule 1? A. It is clear that the volume of gas involved in the Rayne Field purchase is unusually large, since the recoverable reserves are estimated to be of the general magnitude of one trillion cubic feet. Large packages of gas tend to command higher prices than small packages, and this factor should be borne in mind in comparing the Rayne Field purchase with prevailing area prices.

To illustrate this relationship between price and volume, Chart 1 has been prepared on the basis of the contracts filed as rate schedules which are listed in Schedule 1, as summarized for this purpose by Schedule 6.

Q. What do Chart 1 and Schedule 6 show? A. For the purposes of Chart 1, the contracts have been divided into three volume classes: (1) contracts under which annual deliveries are 1200 MMcf or more; (2) contracts under which annual deliveries are 600 MMcf or more, but less than 1200 MMcf; and (3) contracts under which annual deliveries are less than 600 MMcf.

For each volume class there have been calculated (1) the average monthly deliveries under the contracts in that class;

1840

and (2) the median average base price. The results are plotted on Chart 1 by three heavy black dots. For the pur-

pose of this comparison, tax reimbursement has not been added to the prices.

Q. What are these results? A. The median average base price in the small volume class is 21.5¢ per Mcf. The median average base price in the intermediate volume class is 23.2¢ per Mcf. The median average base price in the large volume class is 24.3¢ per Mcf. Thus there is a difference of almost 3¢ per Mcf between the median average base price found in contracts in the large volume class and in contracts in the smallest volume class, and a difference of approximately 1¢ per Mcf between contracts in the large volume class and contracts in the median volume class. This relationship between price and volume is a factor which the Commission should take into account in evaluating the cost of the Rayne Field gas in the light of prevailing area prices.

Q. Is there any other special factor which the data on Schedule 1 suggest that the Commission should bear in mind in comparing the Rayne Field purchase with prevailing area prices? A. I am aware that it has previously been pointed out in this proceeding that the lease-purchase form of transaction has a special value to Texas Eastern because it avoids

future increases in the cost of gas resulting from an indefinite pricing provision, such as a price determination clause which is a frequent characteristic of the gas sales contract. By the same token, the seller gives up something of value when he forgoes the the advantages of an indefinite pricing provision. Where this occurs there is a tendency for the omission of the indefinite pricing provision to be reflected in higher fixed prices in the contract.

Q. I assume you are referring to Chart 2 and Schedule 7 in your exhibit? A. Yes, sir. Chart 2 and Schedule 7 are based on the large volume contracts filed as rate schedules

which are listed in Schedule 1. Using a weighted average of average base prices as a measure, we have compared the average base prices found in contracts containing one or more indefinite pricing provisions with the average base prices found in contracts containing no indefinite pricing provision.

As Schedule 7 shows, where the contract contains no indefinite pricing provisions there is a tendency for the average base price to be several cents higher than where the seller receives the benefit of one or more indefinite pricing provisions. In the case of the contracts covered by Schedule 7, the average of the average base prices in contracts containing one or more indefinite pricing provisions was 23.6¢ per Mcf, and the average of average base prices in contracts

1842

containing fixed prices only was 25.9¢ per Mcf.

Q. Up to this point your testimony has been concerned with the prevailing level of prices in the south Louisiana area in 1958 and the first half of 1959. Would the picture be substantially altered if one looked to prices in a more recent time period? A. No. Schedule 5 presented a summary of prices in the 18-month period which ended June 30, 1959. Schedule 8 is a similar summary of prices under contracts dated since July 1, 1959. As in the case of Schedule 5, the summary covers all long-term sales to interstate pipelines under contracts which have been filed with the Federal Power Commission, including contracts filed with independent producer certificate applications through September, 1961.

Q. How do the results shown by Schedule 5 compare with the results shown by Schedule 8? A. Schedule 5 shows that in the period January 1, 1958, through June 30, 1959, initial base prices plus tax reimbursement range from 13.75¢ per Mcf, up to 24.05¢ per Mcf, and average base

(1842)

prices plus tax reimbursement range from 15.65¢ per Mcf up to 28.45¢ per Mcf. The median initial base price plus tax reimbursement was 23.55¢, with the range for the middle 80% of the volumes being from 20.25¢ to 23.30¢. The median average base price plus tax reimbursement was 25.90¢, with the range for the middle 80 per cent of the volumes

1843

being from 22.55¢ to 28¢. In the later time period, Schedule 8 shows that while the total range of prices was wider, the range of prices for the middle 80% of the volumes narrowed slightly and was at roughly the same level as in the earlier period, whether initial base prices or average base prices are used as the basis. Initial base prices plus tax reimbursement in contracts accounting for the middle 80% of the volumes ranged from 20.67¢ up to 23.60¢, compared with the earlier range of 20.25¢ to 23.80¢.

Average base prices plus tax reimbursement in contracts accounting for the middle 80% of the total volume range from 23.00¢ to 27.90¢, compared with the earlier range of 22.55¢ to 28.00¢. The median price based on initial base prices plus tax reimbursements change from 23.55¢ to 22.83¢. The median price based on average base prices plus tax reimbursement remain the same at 25.90¢ per Mcf.

Q. The preceding section of your testimony has been based on market prices for natural gas as measured by prices in contracts filed with the Federal Power Commission. You state at the outset that you also proposed to consider prices in contracts covering sales which have been certificated by the Federal Power Commission, and that your exhibit includes a schedule on the subject. What is that schedule and what does it cover? A. The schedule to which I referred is Schedule 9.

1844

It listed sales in south Louisiana where the Commission has issued an order granting a permanent certificate, and that order is not under court or commission review. Thus, where an order granting a permanent certificate is subject to further consideration by the Commission because of an order by a reviewing court or because the proceeding has been reopened, the contract or contracts affected have not been included in the schedule. The listing is limited to cases where the average base price provided for by the contract is 20¢ per Mcf or higher. Sales which are being made under temporary authorization are not included.

Q. How are the sales shown by the schedule arranged? A. The sales are arranged by date of certification.

Q. What information on prices is included in that schedule? A. Column J shows the initial base price at which each sale was certificated. Column K shows the initial base price plus tax reimbursement which has been payable under the contract since the end of 1958. Similarly, column L shows the average base price under the terms of the contract, and Column M shows the average base price plus the tax reimbursement which has been payable under the contract since the end of 1958.

As I have previously stated, the FUC has normally allowed the seller to receive the full tax reimbursement called for by

1845

his contract. Footnotes to Schedule 9 show any cases in which the proper amount of the tax has been questioned.

Q. What comments do you care to make on this schedule? A. Looking at Column J of the schedule which gives the initial base price, the schedule shows eight instances in which certificates have been issued to producers at initial base prices of 22¢, and eighteen instances in which certificates have been issued to producers at initial base

prices of 21.5¢. The initial base prices plus tax reimbursement in these 26 cases range from 22.0¢ to 24.05¢. The Commission has been certificating sales with initial base prices of 20¢ since 1954, when the regulation of producers began. These early 20¢ prices were accompanied by tax reimbursement of one cent which has been increased to 1.50¢ or more as the Louisiana tax law has changed.

Q. What do you find when you look at average base prices provided for by the contracts listed in your Schedule 9? A. There are 47 instances in which the average base price is 23¢ or more, and in 28 of these cases the average base price is 25¢ or more, with eight cases in which the average base price is 26.3¢. When tax reimbursement at the rate in effect since December, 1958 is added, the prices for these 47 contracts range from 24.5¢ to 28.35¢.

Q. I understand that the figure you have given in answer to the last two questions are on the basis of the entire time

period covered by Schedule 9. What would be the result if you looked only to certificates issued by the Commission in 1958? A. In 1958, the Commission issued 30 certificates in cases in which the initial base price was 20¢ or higher. In 11 of these cases the initial base price was 21.5¢. When tax reimbursement at the rate in effect at the end of 1958 is added, the tax-inclusive prices in these 29 cases range from 21.75¢ to 23.675¢. In 15 instances the average base prices is 23.0¢ or more, and in 14 of these 15 cases the average base price is 25.0¢ or more.

When tax reimbursement is added to the average base price in these 15 cases, the prices range from 25.475¢ to 27.675¢.

Q. Column I of Schedule 9 shows an annual volume figure for each sale listed. What is the total of the annual volumes for the sales shown on that schedule? A. The total is 423,081 MMcf.

Q. What is the total of the annual volumes shown for the permanently certificated sales where the initial base price and the current tax reimbursement totaled 20¢ or More? A. The total annual volume for such sales is 343,873 MMcf.

Q. If one assumed that the reserves covered by these contracts are 20 times the total annual volumes, how large

1847

would be the reserves represented by permanently certificated sales where the initial base price plus tax reimbursement is 20¢ or more? A. On that assumption the reserves represented by such permanently certificated sales would be 6,887,000 MMcf, or 7 trillion cubic feet.

Mr. Deakins: I now offer Exhibit X-6 and tender the witness for cross-examination.

Presiding Examiner: The offer will be taken under advisement. We will take the morning recess at this time. If there are any clarifying questions you can ask them after the recess.

* * * * * * * * * *

Presiding Examiner: Mr. Lewnes.

Mr. Lewnes: Miss Suchow has some questions.

Miss Suchow: Did you say Schedule 9 of your exhibit includes only certificated contracts which were not appealed?

The Witness: No, I said cases where the order is not under court or Commission review. I know of cases in which efforts were made to take several of the contracts on the list to courts, where those efforts were unsuccessful—

Miss Suchow: Well, would you turn to sheet 6 of the schedule. Below the middle of the page you have listed two sales to Transcontinental Gas Pipe Line Company, one by Sunray Midcontinent and another by Superior Oil Company. Is it

1848

your understanding that the appeals in those cases were unsuccessful?

The Witness: You have me. That is an error. Those two I am sure should not be included.

Miss Suchow: Is it your understanding that the first one was the subject of the 10th Circuit Court's decision in United Gas Improvement against the Federal Power Commission, 290 Fed. 2d 159?

The Witness: If you say so, that sounds right.

Miss Suchow: And does it sound right to you also that the second one was the subject of the 5th Circuit's decision in a case of the same name, reported at 290 Fed. 2d 147?

The Witness: That sounds right too, and as you say, those two should have been omitted.

Miss Suchow: And how about the one under that, the sale by United to the California Company, would you say was unsuccessful?

The Witness: I see now how that error was made. My recollection is that this one also should have been omitted.

Miss Suchow: Is it your recollection that that sale was a subject of decision by the 9th Circuit, reported at 283 Fed. 2d 817?

The Witness: I have no such precise memory for citations.

Miss Suchow: Mr. Furman, as far as Schedules 1 and 8 of your exhibit are concerned, can you give the legal status

1849

of each proceeding; and what I want to know is whether the contracts have been certificated by the Commission, if so, the date, whether certificate applications are presently pending before the Commission, have been consolidate in Area Rate Proceeding 61-2, if certificates have been issued, whether they were appealed, and what the dispositions have been.

The Witness: It would be possible to make such an analysis. I have not done so because, as I think my testimony made clear, I did not take as a test for inclusion or exclusion the status of the sale with reference to Commission certification.

Miss Suchow: Well, Mr. Examiner, with that explanation by the witness I move to strike the entire exhibit and related testimony. I think that insofar as Schedules 1 through 8 are concerned, the witness has stated that they include contracts from 1958 and thereafter. As everyone in this room is well aware, a great many of those contracts were certificated by the Commission, their certifications were reversed by the courts on grounds that the prices had not been proved to be consistent with the public convenience and necessity, and are now before the Commission again in order to determine that very question.

I believe it is undoubtedly true that a great many other contracts listed in this exhibit have not been certificated but are awaiting certification by the Commission in order to determine whether they and their price provisions are consis-

1850

tent with the public convenience and necessity. In view of that it seems to me impossible to use any of the data contained in these schedules as meaningful guideposts for any determination that is to be made in this case. We have been presented time and time again with the use of contract price data which itself or themselves have not yet been established to be consistent with the public convenience and necessity.

An attempt has been made to use such data in order to prove the propriety of a proposed price, and that attempt has been reversed and remanded by the courts on several occasions, and I don't think it worthwhile to go through the same routine again in this case. Unless the contracts

themselves have been established to be required by the public convenience and necessity, are themselves nonsuspect, to use the words of one of the reviewing Courts, I don't think they have any place or any meaning for any relevant purpose in this case.

Mr. Deakins: Mr. Examiner, if what Miss Suchow says is true, the only pertinency of her remarks would go to the credibility of the evidence, and certainly not to strike. As a matter of fact, the evidence has not been received at all yet, so it couldn't be stricken, but that is all the pertinence of that.

I think the exhibits and testimony speak for themselves, with the exception of possible errors which the witness correct-

1851

ed at Miss Suchow's suggestion.

Presiding Examiner: Miss Suchow, what I did was to take the motion to admit the exhibit, I took that under advisement to be ruled upon at the conclusion of the cross-examination thereon. I will let it drop there. I think, however, that the basis of comparison of prices are prices which have been either permanently certificated by the Commission without condition or if there was an appeal from the Commission order to the court then you need the court review on the Commission price, but I will rule on that when we get through with the cross-examination.

Mr. Lewnes: Mr. Furman, referring to your Schedule 9, am I correct in assuming that inherent in your arriving at the average base price, Column L, is the assumption that this Commission will allow all escalations provided for in the contracts listed?

The Witness: It is correct that the average base price is based upon the fixed prices of the entire base price schedule.

Mr. Lewnes: Now the title of that schedule states it is

sales in southern Louisiana permanently certificated by the Federal Power Commission with average base prices of 20.00¢ per Mcf or above by date of certification. Have you made a similar study with the average base price of under

1852

20.00¢ per Mcf?

The Witness: There is, as perhaps you know, basic difficulty in relating certificate docket numbers with rate schedule numbers, and it is only through the establishment of that relationship that the price information which in our files at least has been available on the basis of the rate schedules can be compiled. Accordingly, although we have in south Louisiana gone further than I think in any other area in matching certificate numbers with rate schedule numbers, we have pursued this research only as far as it seemed necessary, and I cannot say to you whether on the basis of the present state of our records it would have been feasible to, for example, include all contracts.

Mr. Lewnes: But you do know of your own knowledge that there are some contracts whose average base price does come out to 20.00¢ or less in given areas?

The Witness: Oh, yes.

* * * * * * * * * *

1853

Gordon L. Jennings

was sworn and testified as follows:

Direct Examination

By Mr. Deakins:

Q. Please state your name. A. Gordon L. Jennings.

Q. By whom are you employed? A. Texas Eastern Transmission Corporation, Shreveport, Louisiana.

Q. Are you the same Gordon L. Jennings who previously testified in these proceedings? A. I am.

Q. What is your present position with Texas Eastern? A. I am presently the supervisor of the Plans and Research Division of the Engineering Department.

1854

Q. When did you assume this position? A. I was promoted to the supervisor's position on May 1, 1958.

Q. In this capacity have you had occasion to make, or have made by personnel working under your supervision, engineering, design, and economic studies to determine the cost of gathering and transporting various blocks of gas reserves and gas supplies through Texas Eastern's gas pipeline system and the cost of delivering these supplies to Texas Eastern's customers? If so, would you please describe the nature of those studies? A. The greatest portion of the work performed by my division is related to the engineering, design, and economic evalution of gas pipeline systems. Prior to the preparation of all of Texas Eastern's applications to expand its system, engineering design studies are made to determine the additional pipeline and compression facilities necessary to provide the additional system capacity. A determination is made of the cost of installing and operating those facilities. By adding the field price of the additional gas supply to the annual costs relating to these additional required facilities, the incremental cost of service can be obtained. Comparison of this incremental cost of service with the revenues to be derived from the sale of the gas will yield a general indication of the economic feasibility of the program.

1855

Q. In your direct testimony in these proceedings which was in connection with Hearing Exhibit No. 50, you indicated that you had assisted in or supervised preparation

of Application Exhibits Nos. F, G, and G-II, contained in a number of Texas Eastern's applications to this Commission, including these same exhibits contained in Docket No. G-12446. Have you supervised the preparation of these same exhibits in applications which have been filed since the preparation of this docket?

If so, would you please state which dockets? A. Since my testimony was presented in this application, I have supervised the preparation of Exhibits F, G, and G-II in Docket Nos. G-17420, G-18968 and G-18969, et al, CP60-122, and CP61-203.

Q. Did you participate in or supervise the work related to engineering design and economic analysis of the facilities applied for in all of the dockets you have listed? A. I did.

Q. In addition to the work related to the engineering design and economic analysis work in the facilities applied for in these dockets, have you prepared or had prepared by personnel working under your direction and supervision engineering studies related to the cost of gathering and transporting the gas from car locations in Texas and Louisiana? A. I have.

1856

Q. Will you describe the nature of these studies and the purpose for which they were prepared? A. These studies were prepared for use by management as guides in determining the price which Texas Eastern might pay for additional supplies of gas. The geographic location of a gas reserve in relation to Texas Eastern's system as well as the magnitude or size of those reserves, are some of the prime factors in determining the value of the reserves.

For example, if gas is to be delivered to the New York market area and is to be sold at a given price, the cost of the gas plus its transportation cost to that market area must be approximately equal to the sale price. The trans-

portation of gas reserves from the extreme southern portions of Texas to New York will naturally bear a greater transportation cost than the movement of gas from a point adjacent to our existing system in South Louisiana because of the greater distance involved.

Therefore, for equal delivered costs in the New York area, the field price in South Texas would have to be less than the field price in South Louisiana. On a number of occasions I have prepared studies to determine the cost of transporting various blocks of gas to a common point on Texas Eastern's system in order that these comparisons might be made.

Q. Have you made any studies from which you can determine

1857

the cost of transporting various blocks of gas reserves to Opelousas, Louisiana, which is the point at which the Rayne Field gas enters the Texas Eastern main line system? A. I have.

Q. Have you made any studies related to the cost of transporting to Opelousas, Louisiana, some of the major additions of gas supplies Texas Eastern has acquired since the original reserves were secured and if so, please describe the nature and results of these studies? A. I have made such studies. The addition of field reserves as distinguished from reserves Texas Eastern purchases from other pipeline companies, field reserves which Texas Eastern has acquired since the original pipeline system was placed in service, consist of three major blocks located in three general areas, namely (1), those reserves purchased along our Wilcox Trend Gathering System, (2) reserves connected to the system in Texas Railroad Commission Districts 2, 3, and 4, along our 30-inch pipeline between McAllen, Texas, and Blessing, Texas; and (3) gas reserves

associated with the purchase of gas from Petrolios Mexicanas, or Pemex, at a point near McAllen, Texas.

I have prepared a map showing the general location of these pipelines, that is, a geographic map.

Mr. Deakins: I will ask that there be marked for identification a one-page map which should be marked, Mr.

Examiner, as Exhibit X-7.

Presiding Examiner: It will be marked Exhibit No. X-7 for identification.

(The document referred to was marked Exhibit No. X-7 for identification.)

By Mr. Deakins:

Q. Did you prepare this exhibit or have it prepared under your supervision and direction, Mr. Jennings? A. I did.

Q. What does this exhibit show? A. This exhibit consists of a geographic map of the Texas and Louisiana Gulf Coast area showing Texas Eastern's pipelines in those areas. Also shown are the boundaries of Texas Railroad Commission Districts 2, 3, and 4, the Wilcox Trend Gathering System is shown as a pipeline with a number of laterals extending from it.

The main trunk line extending from a point near McAllen, Texas, to Blessing Station is also shown and the location of the Rayne Field gas south of Opelousas Station in Louisiana is also shown. The purchase of gas from Pemex is made, as I said, at a point near McAllen on the international boundary between the United States and Mexico.

Q. Now, you were talking about some studies you made, Mr. Jennings. Will you go ahead and continue that answer? A. I have made engineering studies to determine the

1859

approximate cost to Texas Eastern of purchasing and transporting reserves from each of these three major blocks I named to a point on Texas Eastern's system, namely Opelousas Station or Opelousas, Louisiana. The cost of Wilcox Trend gas at Opelousas is 24.0 cents per Mcf, consisting of an existing field price of 14.4 cents per Mcf at 15.025 p.s.i.a., plus 9.6 cents per Mcf for the transportation cost to Opelousas.

The cost of gas purchased in Texas Railroad Commission District 2 and 4, along our 30-inch pipeline to Opelousas is 24.7 cents per Mcf, consisting of an existing price of 15.6 cents per Mcf at 15.025 p.s.i.a., plus 9.1 cents per Mcf transportation cost to Opelousas.

The cost at Opelousas of gas purchased from Pemex is 24.6 cents per Mcf consisting of an existing price of 15.6 cents per Mcf at 15.025 p.s.i.a., plus 9.0 cents per Mcf transportation cost to Opelousas.

Q. What was the source of the information which you used to determine the field cost of the Wilcox Trend, South Texas and Pemex gas which you have just described? A. The prices which Texas Eastern is currently paying for such gas.

Q. How did you determine the most of transporting Wilcox Trend reserves to Opelousas? A. The transportation costs of Wilcox gas contain-

1860

several components. First, I determined the average unit cost of transportation on the Wilcox Trend Gathering System by dividing the total annual charges applicable to this gathering system to include fixed charges on total investment and annual operation and maintenance expenses by the total annual deliveries to the terminus of this gathering system at Providence City, Texas.

This component may be defined as the gathering cost and is approximately four cents per Mcf. To this four cents per Mcf gathering cost must be added the cost of moving this volume of gas from Providence City to Opelousas, which cost is based on the average cost of transportation through the 24-inch pipeline between Providence City and Blessing, Texas, shown on Exhibit X-7 and the average cost of transportation through the 30-inch pipeline system between Blessing and Opelousas, Louisiana, also shown on Exhibit X-7.

As I stated previously, the total cost of transportation which I ascribe to this Wilcox gas in moving it from the fields to Opelousas is 9.6 cents per Mcf. In the case of the reserves Texas Eastern purchases in South Texas in Railroad Commission Districts 2 and 4, the cost is based upon the average cost of transportation through this portion of Texas Eastern's system and is approximately 1.6 to 1.8 cents per Mcf per 100 miles.

The cost of transporting Pemex gas to Opelousas was

determined in a similar manner.

Q. You stated that the field prices you have given previously for Wilcox Trend, South Texas, and Pemex gas are those prices currently in effect, is that correct? A. It is.

Q. Have you computed or had computed the average price of the South Texas and Pemex gas over the life of the various contracts, taking into account the fixed escalation provisions contained in the contracts and if so, state the results of those computations. A. I have. The average price of the South Texas contracts over the life of the contracts will be 16.7 cents per Mcf based on prices paid and production to date and the estimated production and fixed escalation in future years over the life of the contract.

The average price computed in a similar manner of the

gas purchased from Pemex will be 16.8 cents per Mcf over the life of the contract.

Q. Using those prices, have you made a similar computation of the average cost of these blocks of gas at Opelousas, Louisiana, and if so, please state the result of those computations. A. Before I can translate these average long term field prices of the South Texas gas to Opelousas, I must make one further adjustment in the cost of service to account for

field compression which will be required in the later years of the production. It has been my experience that the cost of field compression that will be experienced by Texas Eastern will amount to approximately 1 cent per Mcf for the volume of gas compressed.

Compression will only be required for those reserves produced during the latter years of production and it is my estimate that compression will be required to enable production of the last one-third of these reserves.

Therefore, the cost of compression when related to total reserves, will be approximately one-third of one cent per Mcf or approximately 0.33 cents per Mcf. Using the average price of 16.7 cents per Mcf for the South Texas Gas and adding to this figure the cost of transportation of 9.1 cents per Mcf to move this gas to Opelousas, plus the 0.33 cents per Mcf to account for compression, the average long-term cost of the South Texas gas at Opelousas will be approximately 26.1 cents per Mcf.

The average cost at Opelousas of the Pemex gas over the life of the contract will be 25.8 cents per Mcf. I should note that this figure does not include a compression charge since the Pemex gas will be delivered at the pipeline pressure during the life of production.

Q. Are you familiar in a general way with the fact that Texas Eastern has negotiated for and considered the purchase

of certain other gas reserves of considerable magnitude located in South Texas and off-shore Louisiana? A. I am.

Q. Would you please state what reserves you have been advised that Texas Eastern was considering, the areas in which they are located, and how those facts came to your knowledge? A. As I stated, I have been requested on a number of occasions to make engineering, design, and economic studies of the gathering of gas from a number of locations and its transportation through Texas Eastern's system.

In order to perform this work, it was necessary that I have knowledge of the nature of the gas reserves to include their location, size, the anticipated daily production rates and the pressures at which the gas would be available in the fields. I was aware that these studies would be used in determining the approximate price that Texas Eastern could offer for these reserves. The areas in which gas reserves are located for which I have prepared these studies include reserves located in the Jim Hogg County, Texas, which is located in Railroad Commission District No. 4, reserves located in Duval County, Texas, also in Texas Railroad Commission District No. 4, and gas from various fields located off-shore from Louisiana, including gas from the Ship Shoal area below New Orleans, Louisiana, and gas located in off-shore

areas south of Lake Charles, Louisiana.

Q. Will you please state the nature of the studies you have made concerning the transportation of the gas from these fields? A. In each case an engineering design and cost study was prepared to determine the cost of gathering and transporting these blocks of gas to Texas Eastern's system and the cost of expanding Texas Eastern's system to enable its transportation to some common point.

(1864)

Q. Have you computed the cost at Opelousas, Louisiana, of some of these blocks of gas reserves and if so, would you please give the results of these computations? A. I have. The cost of the Jim Hogg County, Texas, gas I referred to when referred to Opelousas, would be 28.02 cents per Mcf, including a field price at the F.P.C. initial rate of 18.0 cents per Mcf at 14.65 p.s.i.a. or 18.46 cents per Mcf at 15.025 p.s.i.a., the incremental cost of transportation to Opelousas and the 0.33 cents per Mcf compression adjustment.

The cost of Duval County gas, when translated to Opelousas would be 31.68 cents per Mcf determined in a similar manner. The cost of Ship Shoal gas when translated to Opelousas, would be 31.82 cents per Mcf consisting of a price equal to the most recent F.P.C. area price of 24.05 cents per Mcf, including tax reimbursement, plus transporta-

1865

tion cost to Texas Eastern's system.

Although gas from this area would be introduced into Texas Eastern's system at a point some 50 miles east of Opelousas, I have made an adjustment to the transportation cost to account for this more eastwardly location in order to present its cost at Opelousas.

Q. Has Texas Eastern purchased gas from any of these blocks you have just mentioned? A. It has not.

Q. As a result of all of these studies have you been able to arrive at a general rule of thumb for the cost of transporting gas in Texas and South Louisiana which takes into account all of the costs related to its transportation and if so, please state what that rule of thumb might be. A. Based on the many studies which my division has made, it is my observation that the cost of transportation of volumes of gas in the order of 300,000 to 400,000 Mcf a day or more through our major line system is in the order of

1.6 to 1.8 cents per Mcf per 100 miles of distance at 100 percent load factor.

The cost of transportation for the movement of volumes of gas on the order of 200,000 Mcfd would range from levels slightly higher that is from 1.8 to 2.0 cents per Mcf per 100 miles up to 2.5 cents per Mcf per 100 miles for extremely small volumes of gas. These figures apply generally to the

1866

on-shore South Texas and South Louisiana areas. In the case of off-shore transportation, the transportation cost would be approximately 5 cents per Mcf per 100 miles, depending to a great extent on the volume handled.

The cost of transportation of extremely small volumes could be somewhat higher than this 5 cents figure and correspondingly, the cost of extremely large volumes of gas from off-shore areas might be less than the 5 cents per Mcf per 100 miles.

For the purposes of comparisons, which I will make later in my testimony, I use a figure of 5 cents per Mcf per 100 miles for transportation cost off-shore, 2.5 cents per Mcf per 100 miles for transportation cost through an on-shore gathering line, and 1.8 cents per Mcf per 100 miles through a main line system.

In my opinion, these figures represent an approximate minimum cost and the actual cost would be somewhat higher.

Q. Have you been requested to make a computation to determine the cost to Texas Eastern at Opelousas, Louisiana, of gas reserve purchases by other pipeline companies in South Louisiana? A. I have.

Q. Referring you first to the cost at Opelousas of gas from fields for which a price has been permanently certificated by the Commission, have you had occasion to make such an

1867

estimate concerning the gas purchased by Trunk Line in block 26, off-shore Louisiana, in the Vermilion area, and gas purchased by Trunk Line in the north fresh water Bayou Field, Vermilion Parish, Louisiana, and if so, would you give the results of that determination. A. I have. The cost to Texas Eastern of this gas if transported to Opelousas would be approximately 26.52 cents per Mcf based on an initial base price of 22.0 cents per Mcf field price plus 2.05 cents per Mcf tax reimbursement, plus 2.47 cents per Mcf approximate transportation cost to Opelousas.

The price I used for the gas and the tax reimbursement was obtained from Schedule 9 of Exhibit X-6, sheet 5 of 10. I should also note that the volumes of gas from these two fields total approximately 20,000 Mcfd and the transportation cost for a volume this small would be somewhat higher than the transportation cost I have used.

Miss Suchow: Mr. Examiner, before counsel continues I have a motion to strike addressed to the last question and the witness' answer. The question and the answer related to certain prices paid by Trunk Line Gas Company. I believe those prices were certificated in a Commission decision issued after proceeding from which the Public Service Commission was denied intervention on the ground that we could not be affected by the prices paid by this company and,

1868

therefore, I think that by Commission order, anything to do with prices paid by Trunk Line is inadmissible in this proceeding.

Mr. Deakins: That just means we can't prove the facts, is that it, Mr. Examiner? I think the motion is without any merit whatever.

Presiding Examiner: Well, Miss Suchow, let me look at that and I will take it under advisement.

Miss Suchow: The proceeding is Opinion 321 and various orders issued with respect to the Public Service Commission in that case.

Presiding Examiner: I will rule on it for you.

By Mr. Deakins:

Q. Have you make a similar determination for gas purchased by Southern Natural in Iberville, St. Martin, Plaquemines, and Iberia Parishes, shown on sheet 2 of Schedule 17, Exhibit X-6 and if so, will you give the results of that computation? A. First, I believe those are shown on sheet 3.

Q. Yes, they are on sheet 3. A. I have. As shown on Schedule 9, sheet 3 of Exhibit X-6, the initial base price plus tax reimbursement of the gas purchased by Southern Natural in these parishes ranges from 23.0 cents per Mcf to 23.68 cents per Mcf. Using an initial base price of 23.25 cents per Mcf including tax reimbursement,

1869

the approximate cost of this gas, if transported to Opelousas, would be 24.93 cents per Mcf including approximately 1.68 cents per Mcf for the gathering and transportation component.

In my opinion, the 1.68 cents per Mcf I have used for the gathering and transportation component based on the general rules of thumb that I gave is understated because as can be seen from the schedule, this gas is located in a number of fields in rather small volumes and considerable gathering facilities have had to be constructed to gather this gas to some point for transportation.

I believe the actual transportation cost would be somewhat higher than the figure I have used.

Q. Have you made a similar study for gas purchased by United Gas Pipe Line Company in Terre Bonne Parish from the Bayou Piquant, Halter Island, and Lake Hatch

(1869)

fields as shown on sheets 2 and 3 of Schedule 8 and if so, would you please give the results of that determination? A. I have. The cost of this gas at Opelousas would be approximately 24.8 cents per Mcf, consisting of 20.0 cents per Mcf initial base price plus 1.75 cents per Mcf for tax reimbursement plus approximately 3 cents per Mcf for the transportation component. The price data on these fields is also shown on sheets 2 and 3 of Schedule 9, Exhibit X-6.

Q. Have you made a similar determination relating to gas purchased by Texas Gas Transmission Corporation in

1870

Assumption and Lafourche Parishes from the East Lake Palourde and Thibodaux Fields, and if so, would you state the result of that computation? A. I have. These fields are listed on sheet 1, Schedule 9, Exhibit X-6, which shows that the initial base price for this gas is 20.0 cents per Mcf plus a minimum 1.75 cents per Mcf tax reimbursement for a total price at the field of 21.75 cents per Mcf.

Adding to this figure a transportation component of approximately 2.2 cents per Mcf, the value of this gas at Opelousas would be approximately 23.95 cents per Mcf.

Q. Have you made similiar determination of the cost to Texas Eastern at Opelousas, Louisiana, of gas from fields for which the field price is pending certification, namely the gas from Bastian Bay Field in off-shore Louisiana, the gas purchased by Transcontinental Gas Pipeline Company in Blocks 28 and 32 in the Ship Shoal area offshore Louisiana, and if so, would you please state the approximate value of this gas at Opelousas, the price you have used for the gas, and the basis of this price? A. I have. Using the initial base price of 22.0 cents per Mcf shown on sheet 8 of Schedule 1 of Exhibit X-6, the cost of the Ship Shoal gas purchased by Transcontinental, if transported by Texas Eastern to Opelousas, would be approximately 25.6 cents per Mcf including approximately

3.6 cents per Mcf for the transportation component.

I should also state that I have reviewed Tranco's exhibits in their Docket No. G-16603 in which they requested authorization for facilities to gather this gas and have determined that the incremental cost of moving this gas from these two blocks to the shore line is approximately 3.1 cents per Mcf.

This shore line point is approximately 100 miles south of Opelousas. Using the 3.1 cents per Mcf transportation cost to the shore line, plus the 22.0 cents per Mcf price at the field, plus 2.5 cents per Mcf for transportation from the shore line to Opelousas, the cost at Opelousas of this gas would be 27.6 cents per Mcf.

Gas from Bastian Bay translated to Opelousas station would have a cost at that point of approximately 28.16 cents per Mcf, consisting of the 24.8 cents per Mcf initial base price plus tax reimbursement, plus approximately 3.36 cents per Mcf transportation cost.

This transportation component of 3.36 cents includes an adjustment to account for the fact that Bastian Bay gas would have entered Texas Eastern's system at a point east of Opelousas. Therefore, I have translated this cost westwards to some extent. I should also state that the incremental cost on the United Gas Pipeline system for moving gas to the vicinity of Lirette, Louisiana, is approximately 6.0 cents

per Mcf based on an analysis of exhibits contained in their Docket CP60-36. Adding this incremental cost of 6 cents per Mcf to the field price of 24.8 cents per Mcf, the cost of this gas at a point near Lirette, Louisiana, would be 30.8 cents per Mcf.

Lirette, Louisiana, is approximately 100 miles southeast

of Opelousas, so that the cost at Opelousas would be approximately 33.3 cents per Mcf.

Q. Have you made a similar determination for gas purchased by Hope Natural Gas Company in South Louisiana and transported by Texas Gas Transmission Corporation to Texas Eastern Transmission Corporation for delivery to Hope in Ohio and Pennsylvania, and if so, would you state if you were able to determine its approximate cost at Opelousas and the results of that determination? A. I have.

Mr. Flaningam: Would you read that question, please?

(Question was read.)

The Witness: Hope Natural Gas Company purchases gas from a number of fields in South Louisiana, some of which are off-shore, south of Lake Charles. This gas is delivered at the fields to Texas Gas Transmission Corporation which gathers the gas and transports it to Lebanon, Ohio, where it is delivered to Texas Eastern which, in turn, transports it to the delivery points of the Consolidated Natural Gas System.

1873

Texas Gas constructed substantial gathering facilities on their system in South Louisiana to enable them to render the transportation service. The total transportation rate charged by Texas Gas is made up of two components, namely a gathering charge and a transportation charge. The gathering charge consists of 50 cents per Mcf per month of demand plus 1.7 cents per Mcf commodity charge for an average rate at 100 percent load factor of approximately 3.34 cents per Mcf.

This rate is applicable to the cost of service of new and existing facilities on the Texas Gas System which are required to deliver all of Hope's gas to a point in Acadia Parish which point is in the vicinity of Rayne Field.

Using an initial base price plus tax of 23.55 cents per Mcf shown on sheet 10 of Schedule 1 of Exhibit X-6 plus the 3.34 cents gathering cost, the cost of the gas at Opelousas would be 26.89 cents per Mcf.

Mr. Deakins: I now offer Exhibit X-7 and tender the witness for cross-examination.

Presiding Examiner: That will be taken under advisement. I will rule on that after the cross-examination.

Mr. Lewnes: I have a couple of clarifying questions.

Presiding Examiner: Mr. Lewnes.

Mr. Lewnes: Mr. Jennings, have you made a study showing what each Mcf produced at Rayne Field would cost Texas Eastern to move it to Opelousas?

1874

The Witness: I have made my engineering study of the cost of transportation from the point at which our pipeline receives the gas to the main line system, namely the lateral line from Rayne Field to our system.

Mr. Lewnes: You haven't made a study relating to the total cost?

The Witness: No.

Mr. Lewnes: In your reference to some compression that will be required in, I think you said, the latter third of the depletion period, was that in reference to the Rayne Field gas or was that in reference to the gas taken from these other fields?

The Witness: I was referring to the gas which we purchase in South Texas and along the Wilcox Trend Gathering System.

Mr. Lewnes: Will any compression be required in Rayne Field?

The Witness: I couldn't answer that, Mr. Lewnes.

Mr. Lewnes: Would you state how much fuel will be taken from the residue gas stream from Rayne Field?

The Witness: I have no idea.

(1874)

Mr. Lewnes: Could you state who would have the answer to both of the previous questions?

The Witness: Excuse me, do you mean fuel in Rayne—

Mr. Lewnes: No, let me refer you to page 2 of Exhibit X-2

1875

wherein is listed the residue gas under column C. Could you state how much fuel will be taken from this residue gas before it gets to Texas Eastern's main line?

The Witness: I have no idea. The exhibit is not mine. In fact, I haven't even seen it.

Mr. Lewnes: Well, could you state who could give us the answers to both of those questions?

The Witness: One of our later witnesses, Mr. John Jacobs, I am quite sure can give it to you.

* * * * * * * * * * * *

1876

John C. Jacobs

was called as a witness, and having been first duly sworn, testified as follows:

Direct Examination

By Mr. Deakins:

Q. Please state your name and place of residence? A. My name is John C. Jacobs, and I reside in Houston, Texas.

Q. What is your present duty and by whom are you employed? A. I am employed by Texas Eastern Transmission Corporation as vice president in charge of its gas supply.

Q. What has been your education after you were graduated from high school? A. I attended Georgia Tech and received a degree in chemical engineering. Thereafter, I was graduated from Yale Law School with an LLB Degree.

Q. What has been your business experience since you

were graduated from law school? A. 1939 through 1944 I worked as a processing engineer with the then Standard Oil Company of Louisiana, in the Baton Rouge Refinery. During the years 1944, 1945, and 1946,

1877

I worked as a supervisory engineer in Caracas, Venezuela, with the Creol Petroleum Corporation. In this job my responsibilities concerned the estimation of oil and gas reserves, the evaluation of producing properties, the preparation of development programs for newly discovered fields, and the planning and execution of gas conservation projects including the design, construction, and operation of natural gasoline and pressure maintenance plants.

In the years 1948 through 1951 I was employed by the Nebo Oil Company of Dallas, Texas, as attorney-engineer in which job my responsibilities covered all phases of the oil and gas producing business, including obtaining leases, negotiating drilling contracts, supervising the drilling and completion of oil and gas wells, the design, construction, and operation of natural gasoline and cycling plants, and the unitization of producing properties.

During the years 1951 through 1953, I practiced law with offices in Dallas, Texas, and my practice consisted almost entirely of representing independent oil and gas producers in all phases of the business.

During the years 1953 through 1955, I served as chief executive officer of Wilcox Trend Gathering System, Inc., of Dallas, Texas. During my employment with Wilcox Trend, engaged in many activities, including, but not limited to, the negotiation of some 125 gas purchase and gas

1878

sales contracts and the sales contract between Wilcox Trend and Texas Eastern.

In my capacity as chief executive officer of the company,

(1878)

I became familiar with the operation of a natural gas transmission system subject to regulation by the Federal Power Commission, including the handling of problems related to its over-all gas supply, as well as the matter of disposing of gas which the company had acquired by purchase.

In other words, I became familiar, in my opinion, with the operation of a major natural gas transmission system, particularly with reference to problems related to gas supply and acquisition.

Since 1955 I have been the vice president of Texas Eastern Transmission Corporation where all phases of the gas supply of the Texas Eastern system have been my responsibility.

Q. Have you previously testified in these proceedings? A. In the initial stages of these proceedings my predecessor testified and in the reopened proceedings, I testified with the reference to matters dealing with the acquisition of the properties of Rayne Field and the negotiation of the agreements for the acquisition of the leases with the sellers.

Q. Are you familiar in a general way with the testimony which Mr. Osborn will present in these proceedings?

1879

A. I am.

Q. Did you furnish certain information to Mr. Osborn which was the basis of his testimony? A. I did.

Q. What was the nature of that information? A. I supplied Mr. Osborn the information necessary to his preparation of the exhibits showing the estimated future cost of operating the Rayne Field property by Texas Eastern. This information is based upon the Rayne Field legal documents, the DeGolyer & MacNaughton reserve and availability studies which appear in these proceedings as Exhibit X-2 and estimates based on the experience of Texas Eastern and of the oil and gas industry in the operation

of oil and gas producing properties which I can describe in detail.

Mr. Deakins: Mr. Examiner, I have an exhibit entitled "Estimated Residue Gas Production, Rayne Field, Acadia Parish, Louisiana, 1961 through 1989," which I would like to have marked as Exhibit X-5. It consists of 14 pages.

Presiding Examiner: It will be marked Exhibit No. X-5 for identification.

(The document referred to was marked Exhibit No. X-5 for identification.)

By Mr. Deakins:

Q. Now, Mr. Jacobs, referring you to Exhibit X-5, please state in general terms what that exhibit is and by whom

it was prepared? A. Exhibit X-5 is the back-up of the figures which I furnished Mr. Osborn and which are actually the basis of his exhibit. Exhibit X-5 was prepared under my supervision and direction.

Q. Referring you now to page 1 of Exhibit X-5, please state its source and what that is concerned with? A. Page 1 of Exhibit X-5 is a tabulation showing the estimated volume of gas to be produced from Rayne Field for each year of the life of the field, commencing in the year 1961 and ending in the year 1989. This tabulation is identical with the first and second columns on the lefthand side of page 2 of the DeGolyer & MacNaughton availability exhibit which has been numbered Exhibit X-2, and was put into this Exhibit X-5 for the purposes of continuity and for ready reference by anyone who examines Exhibit X-5.

Q. That was the estimated annual production in MMcf for the years 1961 through 1989 with a total which is the estimated recoverable residue gas from the Rayne Field, is that not a fact? A. That is correct. The total is 924,687

(1880)

MMcf which figure was taken from the DeGolyer & MacNaughton Exhibit X-2.

Q. Why was it necessary for you to have these figures shown on page 1 of Exhibit X-5?

1881

A. The annual figures as set forth on that Exhibit X-5 at page 1 represent our estimate of a reasonable method of producing the Rayne Field reserves throughout the life of the field and it is the necessary beginning point for the purpose of making a representative study of the cost of making Rayne Field gas available to the Texas Eastern system.

Q. Referring you now to page 2 of Exhibit X-5, please state what that shows? A. Mr. Marshall of DeGolyer & MacNaughton has testified that it will be necessary for Texas Eastern to drill four additional wells during future years in order to obtain the quantities of gas set forth on page 1 of Exhibit X-5. Page 2 of Exhibit X-5 shows the years in which the four required new wells are to be drilled and Texas Eastern's estimate of the required investment for the drilling of such new wells, the estimated required investment is broken down into tangible and intangible costs which breakdown is based on Texas Eastern's experience of the cost of such matters at the present time.

The total investment in future new wells at Rayne Field is estimated to be $2 million.

Q. What is the basis of your estimate of the cost for the drilling and completion of those wells? A. Our estimate for the cost of the drilling and

1882

completion of the four future new wells at Rayne Field is based on Texas Eastern's experience in Rayne Field and Texas Eastern's knowledge of industrywide experience in drilling and completing oil and gas wells throughout the

Gulf Coast area and particularly in South Louisiana to similar depths and formations.

As in all other parts of Exhibit X-5, the estimates on page 2 of Exhibit X-5 represent only our estimate of the cost of drilling those four wells which is of necessity based on present costs inasmuch as the actual expense at such future time is not known and has not been experienced.

In this instance as in all other cases in these exhibits, we have not attempted to trend the costs of drilling or any other costs to fit costs which will be incurred in some future year such as 1971 or '72 because that is impossible. At the same time it should be pointed out that neither have we trended the income to future values to be received from the sale of gas or liquids from the Rayne Field properties in the instant studies, so the matters have been treated consistently.

Q. Referring you now to page 3 of Exhibit 5, please state what that shows. A. You will recall that Mr. Marshall of the firm of DeGolyer & MacNaughton also testified that he had advised Texas Eastern as to the number of well work-overs which

1883

would be necessary in the future at Rayne Field and the year in which such work-overs will occur, in order that the annual quantities of gas shown on page 1 of Exhibit X-5 may be produced.

Page 3 of Exhibit X-5 sets out my estimate of the cost to Texas Eastern of the well work-overs indicated to be necessary by Mr. Marshall.

These costs are based upon costs incurred by Texas Eastern in drilling, completing, operating, and working over wells throughout the Gulf Coast area with special emphasis upon our knowledge of industrywide experience in South Louisiana when working over wells of the depths and in the formation and at pressures similar to those at Rayne Field.

Page 3 of Exhibit X-5 also sets out my estimate of a split between tangible and intangible expenses involved in the work-overs of 30 percent tangible and 70 percent in-tangible expenses. This split between tangible and intangi-ble expenses is again based upon the experience just out-lined.

Page 3 of Exhibit X-5 further shows that all of the $371,-000 work-over cost will be recovered by Texas Eastern with the exception of $1181. The term "recovered" as used here means that Texas Eastern will be reimbursed for the well work-over costs by the owners of the liquids out of separator liquids produced at Rayne Field in accordance with the legal

1884

documents under which the leases were purchased by Texas Eastern.

Texas Eastern has the right of such recovery until such time as the liquid payments to the former owners of the property terminate, after which time although Texas East-ern has no longer any right of recovery out of liquids, Texas Eastern enjoys a compensating factor, the income from all liquids, which income will more than bear this and all other expenses of development and operation of the leases.

The liquid production payments terminate when approx-imately 75 percent of the gas has been produced. In the case of some of the small purchases made subsequent to the purchase from Continental Oil Company, et al, the pro-duction payments will terminate as early as 1970, with a consequence that some small portions of the 1971 and 1972 work-over costs do not fall in the "recoverable" category.

As I have stated previously, the "nonrecoverable" costs amount to 1181 dollars. However, the liquid income to Texas Eastern allocable to the working interest from which

the production payment has terminated will more than cover the $1181 share of the well work-over costs.

Q. Referring you now to page 4 of Exhibit X-5, please state what that is? A. Page 4 of Exhibit X-5 sets out the cost to Texas Eastern by years for estimated replacement of tubing in the

Rayne Field wells which on the basis of experience, might be necessitated by corrosion. I have estimated that tubing replacements might be required in each well every 10 years and that each replacement of tubing will cost $75,000. These estimates of tubing life and replacement costs are based upon our past experience and the past experience of others in the industry in operating gas wells to the depths and at the pressures which exist at Rayne Field. In connection with tubing life, I should state that the tubing at Rayne Field is plastic-coated and that the technical advances of plastic-coated tubing will definitely extend the life beyond that expected for uncoated tubing. Page 4 consistent with the other pages of Exhibit X-5 which have been described, sets out a breakdown of the total estimated cost of tubing replacements of $2,850,000 into the recoverable and nonrecoverable categories. Inasmuch as Texas Eastern is entitled to recoup those sums and is also divided to indicate that share of the total expenditure which represents tangible expenses and that share which represents intangible expenses which are estimated on the basis of my knowledge of such costs.

Q. Now, referring you to page 5 of Exhibit X-5, please state what that shows? A. Page 5 of Exhibit X-5 sets forth my estimate of the required investment to tie the four new wells to be drilled

1886

as set forth on page 2 of Exhibit X-5 into the Central Rayne Field separator plant which investment is in the amount of $360,000.

Q. What was that figure? A. Which is in the amount of $360,000. As is the case with the prior described pages of Exhibit X-5, the figures on page 5 are broken down to show recoverable and nonrecoverable portions of the total expenditures all of which are tangible costs and are based on actual experience of such costs which have been incurred by Texas Eastern.

Q. Referring you now to page 6 of Exhibit X-5, please state what that is? A. Page 6 of Exhibit X-5 sets out the estimated cost of a low pressure gathering system which will be installed at Rayne Field in the future to permit the gathering of gas from wells with lower wellhead pres- sures when such pressures have been reduced by produc- tion to a central point in the field under a gathering ar- rangement involving high pressure and low pressure sys- tems and which will result in the lowest reasonable operat- ing cost.

Again and consistent with the prior pages of Exhibit X-5, the indicated investment of $550,000 is shown to be tangible and completely recoverable out of liquids. In this case as in the case of the estimates on page 5, these esti- mates are based upon our estimates of present costs for similar

1887

facilities.

Q. Referring you now to page 7 of Exhibit X-5, state what that demonstrates. A. Page 7 of Exhibit X-5 sets forth an estimated investment in future field compression facilities at Rayne Field of $4,800,000, which would be oc- casioned by the inevitable gradual reduction in flowing

wellhead pressures at Rayne Field as the reservoirs are depleted of their recoverable reserves of natural gas.

All of the $4,800,000 investment is recoverable out of liquids with the exception of $48,496 and all of the investment falls into the tangible category.

Q. How do you estimate that it will be necessary to install compression in the years that you have shown and at the cost which you have shown on page 7 of Exhibit X-5? A. The investment in compression facilities shown on page 7 of Exhibit X-5 is based upon an investment of $300 per installed horsepower of field compressors which figure is accepted in the industry as a reasonable cost of such compression. The number of horsepower were calculated on the basis that gas will be compressed to 1050 p.s.i.g. central point delivery and on the basis of the flowing wellhead pressures and volumes given us by Mr. Marshall of DeGolyer & MacNaughton as indicated in his testimony.

Q. Referring now to page 8 of Exhibit X-5 state how the

well operating costs and maintenance set out there were determined as estimated for each year? A. The referred to operating and maintenance costs are based upon an estimate of $1500 per month per well completion to cover all direct well maintenace expenditures such as corrosion control, all well repair work other than work-overs and tubing replacement, all direct well labor, and all overhead charges including direct division and main office overhead.

The figure of $1500 per month per well completion is based upon Texas Eastern's experience in operating the Rayne Field wells since July 27, 1959. Page 8 of Exhibit X-5 is also arranged in columns to show that $6,035,500 of the estimated $11,141,280 total well operation and maintenance costs will be recoverable out of the liquid production payment.

As I have heretofore explained, the value of the liquids

after the expiration of the production payment will exceed all development and operation costs.

Q. Now referring you to page 9 of Exhibit X-5 which deals with compressor operating costs, please state the basis of those estimates. A. The compressor operating costs set forth on page 9 of Exhibit X-5 cover all operating and maintenance expenses with the exception of compressor fuel and are based upon an

1889

estimated expenditure of $15 per brake-horsepower in operation per year.

The $15 figure is based upon Texas Eastern's experience and its knowledge of industrywide experience in the operation of field compressors and is reasonable. Page 9 of Exhibit X-5 also indicates that $1,197,639 of the total compressor operating costs of $2,340,000 will be recoverable out of the liquid production payment under the pertinent agreements.

1890

Q. What does page 10 of Exhibit X-5 show? A. Page 10 of Exhibit X-5 is an estimate of the revenues which will be realized by Texas Eastern from the sale of its net interest in the production of separator liquids. The figures on page 10 of Exhibit X-5 are based upon a realization of $3 per barrel of condensate, which is equal to the present selling price of $3.20 per barrel, less 20c per barrel severance tax levied by the State of Louisiana. The column on the left-hand side of page 10 of Exhibit X-5, entitled "Gross Condensate" sets forth gross condensate production in barrels for each year of the life of Rayne Field. These figures are identical with those set forth in column D of page 2 of Exhibit X-2, which was the testimony of Mr. Marshall, of the firm of DeGolyer and MacNaughton.

As shown on page 10 of Exhibit X-5, 81.58729% of the

gross condensate production is attributable to the working interest owned by Texas Eastern at Rayne Field. Under the deeds which cover the production of liquids at Rayne Field, Texas Eastern is entitled to retain all of the income from the sale of separator liquids after the termination of the liquid production payments retained by the former owners.

Page 10 indicates that 4,154,110 barrels of condensate will come to Texas Eastern free of production payments, and will have a value of $12,462,330.

Q. Referring you now to page 11 which is entitled

"Revenues from Sale of Plant Liquids Attributable to Texas Eastern's Net Interest in Production," please state the source of the figures shown there. The source of the annual volume figures set forth in the column on the left-hand side of page 11 of Exhibit X-5, entitled "Gross Plant Liquids" is column E of page 2, of Exhibit X-2, which was testified to by Mr. Marshall, of DeGolyer and MacNaughton.

The source of the 1.693 dollars per barrel valued on page 11 of Exhibit X-5 for plant liquids from the Rayne Field processing plant storage tanks is the present sales value of such liquids, less the Louisiana severance tax.

Presiding Examiner: Mr. Deakins, let's take the afternoon recess at this time. This seems to be a convenient breaking point.

(Whereupon, at 12 Noon a recess was had to 12:10 p.m.)

Presiding Examiner: Are you ready, Mr. Deakins?

Mr. Deakins: Yes, Mr. Examiner.

By Mr. Deakins:

Q. Mr. Jacobs, you referred to acquiring small reserves along the Texas Eastern system. Are there any large re-

(1891)

serves located in the off-shore areas? A. Yes, but the location of such reserves in the remote off-shore area would result in a cost to Texas Eastern ranging from 5 to 10 cents per Mcf in excess of the cost of Rayne Field gas.

1892

Q. Would the acquisition of such new gas supplies have any triggering effect on your favored nations clauses in the Texas Eastern contracts? A. Yes, the acquisition of such new gas supplies at current prevailing prices in Texas Eastern's gas supply area would trigger favored nations clauses in Texas Eastern's existing contracts by an amount in excess of $10 million per year, which will result in an additional cost to the consumer of not less than 20c per Mcf per year for a reserve comparable in size to the Rayne Field reserve. Thus, in my judgment, connecting a substitute reserve for the Rayne Field to Texas Eastern's system at today's prices under gas purchase contracts would result in an increase in cost of between 25c and 30c per Mcf over the cost of the Rayne Field gas. Some of such increase in cost might ultimately be disallowed by the Commission. However, I do not believe that anyone would predict that all of the increase would be disallowed, especially since it would include substantial capital expenditures for connecting and transporting the substitute reserves to the vicinity of the Rayne Field.

Q. Do you have any opinion as to whether Texas Eastern has realized any substantial advantages by purchasing the Rayne Field leases rather than acquiring the same gas under gas purchase contracts, such as those which were introduced in the first phase of these proceedings as Hearing Exhibits

1893

3-C, 3-D, 3-E, and 3-F? A. My entire testimony has elaborated the many advantages to Texas Eastern, its custom-

ers, and the consuming public of the acquisition of Rayne Field through the leasehold purchase arrangement. The principal advantages may be summarized as follows: (a) by purchasing the leasehold interest, Texas Eastern avoided the triggering of favored nations clauses and also avoided any effect on future price redetermination clauses of any nation triggering would amount to some 20¢ per Mcf of Rayne Field gas.

(b) The Rayne Field gas has been acquired by Texas Eastern at a lower cost than any other gas which was available to Texas Eastern to meet the demands which are of record of its customers and the ultimate consumer. Not only has the Rayne Field gas been acquired at a cost less than the prevailing area price, but the reduction in gathering and transportation charges which flow from the acquisition of a large reserve located adjacent to Texas Eastern's main line are in the order of magnitude of 5¢ to 10¢ per Mcf. The lower costs are also the consequence of the dollar consideration which was negotiated for the purchase of the Rayne Field leaseholds together with such contractual arrangements as that whereby Texas Eastern can recover compression and operating expenses out of the liquids produced at the field.

1894

By way of a comparative example, if Texas Eastern had purchased a comparable volume of south Louisiana gas from scattered smaller fields at today's prices, which range upward of 24¢ Mcf, Texas Eastern would also have incurred an increase in gathering and transportation costs of at least 5¢ per Mcf, whereas the Rayne Field lies practically adjacent to our lines and the gathering and transportation cost to put Rayne Field gas in our main line at Opelousas, Louisiana, is approximately 0.4¢ per Mcf.

The increase gathering and transportation cost would mean that the gas in our example would have cost Texas

Eastern 29¢ per Mcf. In addition, favored nation increases of 20¢ per Mcf would have been incurred. The total cost of such gas to Texas Eastern would have been 41¢ per Mcf, a figure, the magnitude of which emphasizes the benefits to the consumer of the Rayne Field acquisition by Texas Eastern.

(c) The foregoing discussion does not give an exact dollar value to the advantages to Texas Eastern growing out of the flexibility of deliveries of gas inate in the complete ownership of a reserve of the size of Rayne Field, which is approximately one trillion cubic feet of gas, but the advantages to be gained have great value, as will be seen. In the supplement to Texas Eastern's application filed after the Commission's order of July 14, 1961, it is shown that since Texas Eastern acquired Rayne Field, deliveries out

of the field have varied from zero Mcf per day to as much as 181,679 Mcf per day. This is an extremely wide variation when compared to the plus or minus 20% variation in deliveries possible under many south Louisiana gas purchase contracts and the 25% variation in deliveries permitted under the former gas purchase contracts at Rayne Field. This wide range in deliverability is of great importance in operating a pipeline system to meet the demands of consumers, although no quantitative Mcf is placed on such value to Texas Eastern.

For example, at times during peak sales demand in the winter season, freezing storms, the so-called "northers" come into the Gulf Coast supply area, with the consequence that deliveries may cease at any number of sources of small supply as a result of the low temperature atmosphere produced by the storm. Under the circumstance, Texas Eastern can call on Rayne Field for large quantities to offset

the loss in supply due to freezing and thus obviate the curtailment of any deliveries to the consumer. On the other hand, many of Texas Eastern's contracts, as is customary in the Gulf Coast supply area, contain the so-called "take or pay for" provisions under which the pipeline buyer is obligated to either take or pay for a specific quantity of gas each year, whether taken or not.

The ability to reduce deliveries from Rayne Field as compared with gas purchase contracts is of considerable advantage

1896

to any pipeline charged with the responsibility of providing gas for the consumer in the quantities and at the times the consumer needs gas in being able to balance the overall operation of the pipeline so that the specified quantities of gas are taken under the several take or pay for gas purchase contract provsions.

(d) Rayne Field represents the acquisition of a very large reserve which is located close to Texas Eastern's main line. A large reserve in an advantageous location presents a more attractive proposition to Texas Eastern than the other reasons outlined hertofore. The advantage to the public of the acquisition by a natural gas company, because of the size and location of reserves, have been recognized under the Natural Gas Act as factors which must definitely be considered in deciding a proper field price for gas. For example, due primarily to the location factor, gas prices approved under the Natural Gas Act in New York, Pennsylvania, and West Virginia average 25 to 30 cents per Mcf, as set forth in the recently issued Federal Power Commission report entitled "Sales by Producers to Interstate Natural Gas Companies—1960," which prices are considerably higher than gas prices in the Gulf Coast area.

To summarize all of the foregoing, the Rayne Field leasehold acquisition provides a gas supply to Texas Eastern

(1896)

at a definitely lower price than could gas be made available from any alternative source of supply, then or now. Indeed, Rayne

1897

Field gas under the leasehold acquisition which has been worked out by Texas Eastern will cost the ultimate consumer, if triggering of favored nations clauses is ignored, from five to ten cents per Mcf less than with gas from any alternative source, and will cost the ultimate consumer from 25 to 30 cents less per Mcf than gas from any alternative source if the tiggering of favored nations clauses is taken into account.

I have discussed at length the difficult program which has been in effect as Texas Eastern's gas-buying policy aimed at holding gas purchase costs to a minimum, or in words apropos of Federal Power Commission regulation to hold the line.

In my opinion, on the basis of the Rayne Field cost as shown in the record of those reopened proceedings of testimony in these proceedings regarding the cost of gas from alternative sources of supply to Texas Eastern, of evidence regarding advantages inherent in Rayne Field from such standpoints as location, and flexibility in deliveries, of testimony regarding field prices for other gas purchase contract gas in south Louisiana and the gathering and transportation cost of such gas, and of the opinions written where the courts have directed the Federal Power Commission to consider holding the line in its certificate activity, the acquisition of Rayne Field gas by Texas Eastern Transmission Corporation through the

1898

acquisition of the leasehold interest holds the line.

While it is, of course, not exact as to what will be the future history of this field, there is also the definite possi-

bility of future discoveries and production history which increase the gas reserves and at the same time decrease the net cost per Mcf of gas produced from Rayne Field. This has been indicated in the testimony of Mr. Olson in connection with the new Homeseekers D-2 and D-4 sands and, of course, there may be others.

Mr. Deakins: Mr. Examiner, I now offer Exhibit X-5 and tender the witness for cross-examination.

Presiding Examiner: The offer will be taken under consideration.

* * * * * * * * * *

1899

Mr. Lewnes: On page 13 of the same exhibit could you reconcile the figure on the bottom of 990 million Mcf, with the figure appearing on the bottom of page 1 of the same exhibit?

The Witness: Yes, the 990 million Mcf figure set forth at the bottom of page 13 represents the total field reserves

1900

at the time Texas Eastern took over the field. If you will go back to the record in the prior proceedings, the DeGolyer and MacNaughton reserve study set forth the recoverable pipeline gas reserve of 988 billion cubic feet which, in my testimony, I rounded off to 990 billion.

Now if you will take—what we are doing is reconciling the 990 billion figure with the DeGolyer and MacNaughton exhibit which was testified to today, which is Exhibit X-2. If you will go to the page of Exhibit X-2 which is entitled "Estimated Residue Gas, Condensate, and Plant liquid Reserves," the residue gas reserve is shown to be 924,678 MMcf, on line 27. On line 19, the cumulative production is shown to be 82,414 MMcf. If you add those two numbers together the original recoverable reserve was 1 million 007 thousand 092 Mcf. Now if you will go back to DeGolyer

(1909)

and MacNaughton reserve exhibit in the prior hearings which set forth the 988 billion cubic foot number, the number comparable to line 27, on the page you are looking at, is 988,771 MMcf. To that was to be added past production of 17,018 MMcf for a total original recoverable reserve of 1,005,789 Mcf, so the 990 figure is consistent with the DeGolyer and MacNaughton reserve estimate which has been put into evidence today as well as the prior reserve exhibit that was put in with DeGolyer and MacNaughton, as far as the total amount of gas which has been purchased by Texas Eastern is concerned.

* * * * * * * * *

1919

By Mr. Deakins:

1920

Q. We have heretofore discussed the gas purchase contracts covering the Erath and West Cameron Fields listed on that exhibit. In your opinion, are the reserves covered by any of the other gas purchase contracts shown thereon comparable to the Rayne Field reserves? A. No, none of such reserves are comparable to the Rayne Field reserves in magnitude. Further, many of such reserves are located in much more remote, inaccessible areas.

Q. In your opinion, can the final certificated prices shown on Exhibit X-6 be compared to the cost of the Rayne Field acquisition without adjustment? A. Most certainly not. In my opinion, substantial adjustments upward must be made to the prices shown on Exhibit X-6 in order to obtain any valid comparison between such prices and the cost of the Rayne Field lease acquisition particularly if we are concerned with the ultimate cost of the gas to the consumers in our market area.

The fact that the reserves covered by such contracts are relatively small in comparison to the Rayne Field reserve

requires a substantial upward adjustment in the gas purchase prices for comparative purposes.

For example, gas purchase contracts entered into by the United Gas Fuel Company at the time it entered into the Erath Field contract contained prices ranging from 16 cents to 20 cents per Mcf, depending upon the size of the reserve

contracted for and initial prices under American-Louisiana gas purchase contracts ranged from 18.25 cents to 20 cents per Mcf, depending upon the size of the reserve contracted for.

Moreover, the relatively small gas reserves covered by the contracts listed on Exhibit X-6 are scattered and some of such reserves are located in relatively inaccessible off-shore and bay water areas so that the cost of gathering and transporting a volume of gas from these individual fields equivalent to the volume available at Rayne Field would add several cents to the ultimate cost to the consumer.

Additional savings in costs are realized by acquiring a large volume of gas from a single field, rather than from a number of different fields, such as savings in compression, maintenance, and dispatching costs. In addition, all of the contracts shown on Exhibit X-6 contain provision for fixed price escalations and most of such contracts also contain provision for indeterminate price increase through favored nation price redetermination and other similar indeterminate pricing clauses.

increases. When all of the advantages of the Rayne Field

As I have heretofore pointed out in my testimony, it is recognized throughout the industry and by the Federal Power Commission that the sale of gas for a fixed price should and does command a price higher than the prevailing price under contracts containing provision for indeterminate price

1922

increases. When all of the advantages of the Rayne Field lease acquisition to Texas Eastern and its customers are taken into account, it would require an upward adjustment of between 8 and 12 cents per Mcf depending upon the location and size of the particular field involved to the location and size of the particular field involved to the contract prices shown on Exhibit X-6 to make such prices comparable to the Rayne Field lease acquisition costs.

Q. In your opinion, is the cost of the Rayne Field leases in line with the prevailing area prices? A. In my opinion, the cost of the Rayne Field leases is far below the prevailing uncontested certificated gas purchase contract prices in the area.

Q. Does Texas Eastern need the Rayne Field gas reserve to meet its customer requirements? A. Texas Eastern has a most pressing and urgent need for such gas reserves. For example, in this proceeding the Commission authorized Texas Eastern to expand its main line transmission facilities and make additional sales in the amount of approximately 100,000 Mcf per day.

Subsequently in Docket No. 60-122 Texas Eastern received temparary authority to make an additional 50,000 Mcf per day available to its customers and in Docket No. CP61-203, Texas Eastern proposes an expansion involving sales of 225,000 Mcf per day to meet the urgent additional requirements of its customers.

1923

Obviously if Texas Eastern's system should be deprived of the very large and valuable Rayne Field gas reserve, we would be severely handicapped in meeting even our existing commitments to our customers and our ability to continue to supply their increased demands would be placed in serious jeopardy.

Q. If Texas Eastern should be required to disconnect the Rayne Field reserve from its system, could Texas Eastern replace such reserve along its system with a comparable quantity of gas within a reasonable period of time? A. In my opinion, it would require several years to replace the Rayne Field gas reserve with a comparable quantity of gas. To my knowledge, there are no easily accessible gas reserves on the market in Texas Eastern's gas supply area of a size comparable to the Rayne Field reserves.

Therefore, in order to obtain a comparable quantity of reserves along its system, Texas Eastern would have to attempt to negotiate a large number of gas purchase contracts for much smaller gas reserves scattered along its system. It would obviously take many months to attempt to negotiate such contracts and even if we should be successful in acquiring a comparable size reserve, we would encounter an additional delay of many more months in certificate proceedings and the construction of lateral and gathering lines to these fields.

Q. If Texas Eastern were successful in negotiating

1924

gas purchase contracts for such reserves, could they be acquired and delivered to Texas Eastern's customers at a cost equal to the cost of acquiring and delivering the Rayne Field gas reserves? A. In my opinion, it would be impossible to acquire such a gas supply at a cost equal to the Rayne Field leases. The exhibits of Mr. Furman in this proceeding reveal that the current prevailing price for gas in South Louisiana exceeds Texas Eastern's acquisition cost in the Rayne Field leases and it is common knowledge that the prices being paid and offered for gas along the route of Texas Eastern's pipelines in Texas is rapidly approaching the South Louisiana price level.

The added cost of gathering and transporting the gas from a number of scattered relatively inaccessible fields

to the Rayne Field Vicinity would, in my judgment, increase the cost of such new gas supplies to the consumers in an amount ranging from 5 cents to 10 cents per Mcf in excess of the cost of the Rayne Field gas.

* * * * * * * * * *

1930

Miss Suchow: Now, I would like to tie down the reserve figure that you were relating for Mr. Lewnes before, to the geological exhibit. Did I understand you to say that the 990 million Mcf shown on page 13 of your exhibit is really a rounding of an actual figure of 998,771,000 Mcf?

The Witness: 998,771,000 Mcf.

Miss Suchow: Is that the amount of the gas in place at the time that Texas Eastern bought the leases?

The Witness: Yes, that is not the gas in place, it was

1931

the recoverable pipeline gas.

Miss Suchow: The recoverable gas at the time Texas Eastern asquired the leases?

The Witness: Yes.

Miss Suchow: Now, did I correctly understand you to say there had been 17,000 MMcf production prior to that time?

The Witness: Yes.

Miss Suchow: So that going back to that geological exhibit, X-2, I believe, line 19 of the first sheet which shows estimated cumulative production to January 1, 1961 of $82,414 MMcf, that would reflect 17,000 MMcf production prior to the time that Texas Eastern acquired the leases and approximately 65,000 from when to when, sir?

The Witness: From the time we acquired the leases until January 1, 1961.

Miss Suchow: From the time you acquired the leases, that would be in July of 1959?

The Witness: July of 1959.

Miss Suchow: Thank you. That is all.

* * * * * * * * * *

Stewart P. Osborn

was called as a witness, being first duly sworn, and testified as follows:

Direct Examination

By Mr. Deakins:

Q. Please state your name and place of residence. A. My name is Steward P. Osborn, and I am a resident of Houston, Texas.

Q. What is your present duty and by whom are you employed?

A. I am employed by Texas Eastern Transmission Corporation as Comptroller.

Q. Have you previously testified in these proceedings? A. I have.

Q. Have you prepared or had prepared under your direction exhibits for presentation in this case? A. I have.

Q. What is the nature of those exhibits? A. In the order reopening the proceedings, prescribing procedures and fixing the date of the hearing, the Commission in ordering clause B(3) and (4) ordered Texas Eastern to prepare the following exhibits: An exhibit showing the proposed method of accounting by Texas Eastern for the Rayne Field transaction and all costs incident thereto, and an exhibit showing the cost of making natural gas available from Rayne Field to Texas Eastern's system, and reflecting the estimated annual changes in the cost of the Rayne Field gas through to the estimated year of abandonment.

These exhibits were prepared by me and persons under my direct supervision, and are marked for identification purposes as Exhibit X-3, which is the proposed method of accounting, and Exhibit X-4, cost of making natural gas in Rayne Field available to the Texas Eastern system.

Mr. Deakins: Mr. Examiner, I presume it will be agreeable with the Examiner to continue the marking in the manner

suggested by the Examiner.

Presiding Examiner: That will fill out the numbers in my numbering system.

(Whereupon the documents referred to were marked for identification as Exhibits X-3 and X-4.)

By Mr. Deakins:

Q. Please state in general terms what Exhibit X-3 shows. A. In accordance with the Commission's order, Exhibit X-3 shows the proposed method of accounting by Texas Eastern for the Rayne Field transaction, and all costs incident thereto. This exhibit is prepared in narrative form and is self-explanatory.

Q. Now referring you to what has been marked for the purpose of identification Exhibit X-4, entitled "Rayne Field Cost of Gas, Years 1961-1989," please explain column by column the items set out thereon. A. Column A states the years through the estimated year of abandonment. The figures in Column B show the annual amortization of the note payments on a unit of production basis. The total amount of column B is $117,487,000.

Q. I notice that for the years 1961 through 1973, the charge is shown at the same figure while thereafter it reduces until there is a very small item the 29th year. Please state upon what basis these write-offs were estimated.

A. The annual costs shown in column B are related to the working interest production of natural gas each year. The total annual production was estimated by DeGolyer and MacNaughton and is shown in Exhibit X-2. To the annual working interest production we applied a unit price of 15.5731 cents per Mcf to determine the annual depletion of the gas reserve.

The unit price was arrived at by dividing the total of $117,487,000 by the total recoverable working interest reserve which is 754,420 MMcf. The total working interest reserve of 754,420 MMcf is 81.58729 per cent of the total estimated reserve at January 1, 1961, which amount was 924,678 MMcf. The working interest percentage was furnished to me by Mr. Jacobs and is shown in Exhibit X-5.

Q. Referring you now to column C, how did you compute the depreciation of the tangible plant as shown in that column? A. The annual depreciation expense each year was computed on a unit of production basis. The unit of production basis relates to the recoverable working interest reserves. The total amount of depreciation for the years 1961 through 1989 is $6,190,700, and is based on the balance of tangible plant as of January 1, 1961, and on future additions furnished by Mr. Jacobs. These additions are shown in detail in Exhibit X-5.

Q. How did you calculate the unit cost which you used in making this determination?

A. The depreciation rate per Mcf was determined by dividing the balance of undepreciated property at January 1 of each year by the remaining Mcf applicable to the working interest reserves at January 1 each year. This rater per Mcf times the working interest production during the year developed the estimated depreciation expense for that year.

Q. Referring you now to column D of Exhibit X-4, entitled "Depletion of Natural Gas Producing Leaseholds" state on what basis that depletion was computed. A. Depletion of natural gas producing leaseholds was computed on a unit of production basis. The balance of leasehold investment to be written off as of January 1, 1961, was $7,956,300, and this was written off at a rate of 1.0546¢ per Mcf of working interest production. The unit price was arrived at by dividing the amount of $7,956,300 by the total recoverable working interest reserves of 754,420 MMcf.

Q. What was the basis of amortization of intangible drilling costs which you have shown in column E of Exhibit X-4? A. The annual amounts of amortization of intangible drilling costs were computed on a unit of production basis. The unit of production basis relates to the recoverable working interest reserve. The total amount of amortization of intangible drilling costs is $2,416,800, and is based on the balance of intangible drilling costs as of January 1, 1961, and on future additions supplied to me by Mr. Jacobs. These costs are also

1940

supported by Exhibit X-5.

Q. Now how did you calculate the unit cost which you used in making this determination? A. The unit cost per Mcf with respect to amortization of intangible drilling costs was determined in the following manner: The unamortized balance of intangible drilling costs at the beginning of each year was divided by the recoverable working interest reserve at the beginning of each year, which gave me a rate per Mcf. I applied this rate per Mcf to the working interest production each year to determine the annual amortization of intangible drilling costs.

Q. Referring you now to column F, what does that show? A. This is the net credit to the cost of gas in the Rayne

Field in the amount of $9,031,200. This amount is the difference between the total operating revenues received from sale of liquids of $16,413,600 and the Rayne Field operation and maintenance expenses in the amount of $7,382,400. This transaction does not take place until the production payments for liquids terminate. These various production payments start terminating in the year 1970, and the last one is in the year 1975.

The estimated liquid revenues and expenses were supplied to me by Mr. Jacobs and are also set forth in Exhibit X-5.

Q. How is the total cost of gas, as shown in Column G of exhibit X-4, computed?

A. This is a summation of columns B, C, D and E, less the amount shown in column F.

Q. How did you compute the cost per Mcf shown in column H? A. The annual costs per Mcf shown in column H were derived by dividing the amounts for each year shown in column G by the volume of working interest gas estimated to be produced during each year.

Q. You previously testified that the average cost of this working interest gas was 17.15¢ per Mcf. In the present study, the average cost of such gas is 16.57¢ per Mcf. Please explain the reduction of .58¢ per Mcf in the cost of gas which you have shown on Exhibit No. X-4. A. The amount of 17.15¢ included 15.57¢ for the amortization of the note payments and 1.58¢ for amortization of leaseholds and facilities. This was 1.58¢ was related only to the original acquisition of leaseholds and facilities from Conoco, et al., which amounted to $12,420,500.

In the present study we have included additional development costs as well as the acquisition of leaseholds and facilities of four other parties in the Rayne Field. In addition we have also included future development costs in

(1941)

Rayne Field as set forth in Exhibit X-5. All these items totaled $5,237,100, and increased the amount to be amortized over the life of the field, bringing the new amortization per Mcf up to 2.20¢. In the present study we have applied a credit

1942

against this amount of 1.20¢ per Mcf. This results from the liquid revenues which Texas Eastern will retain after completion of the production payments less the operating expenses of the Rayne Field. The total cost in the present study thus amounts to 15.57¢ for depletion, plus 2.20¢ for amortization, less 1.20¢ credit for liquids, or 16.57¢.

Q. Is Texas Eastern obligated to make royalty payments on the gas produced from the Rayne Field? A. Yes, the Rayne Field leases are on the usual type commercial oil and gas lease forms which obligate the working interest owner to account for royalty portion of gas produced and saved from the leases on the basis of the market value of the gas at the well.

Q. What amount per Mcf is Texas Eastern currently paying to the royalty owners under the Rayne Field leases? A. Texas Eastern is currently accounting to the royalty owners on the basis of a market value of 22.6¢ per Mcf for the royalty portion of the gas produced and saved from the leases.

Q. How is the Louisiana gas severance tax treated in your accounting to the royalty owners? A. Texas Eastern pays to the State of Louisiana gas severance tax applicable to the royalty owners so that they receive a net amount of 20.3¢ per Mcf for the royalty gas after such tax deductions.

1943

Q. Did you include these royalty payments in your computations of the acquisition cost of the Rayne Field leases? A. No, because I do not believe that royalty payments can

properly be considered as a part of the leasehold acquisition costs. In acquiring the Rayne Field leases, Texas Eastern acquired only the working interest in such leases and our agreement with the working interest owners had no relation to or bearing upon the payments to the royalty owners.

As I have previously explained, the royalty owners are entitled to receive the market value at the well for royalty gas but this right did not grow out of Texas Eastern's acquisition of the leases. On the contrary, it is a pre-existing right which was created by the execution of the leases. Further, the obligation to pay royalty on the basis of the market value of gas at the well is not peculiar to the Rayne Field leases but instead is common to practically all oil and gas leases in the Gulf Coast area.

Since the royalty payments were not a part of or affected by the Rayne Field acquisition and will be the same as Texas Eastern would have paid had it acquired the leases as wildcat leases before any gas discovery and will also be the same as any producer of gas in the same area would pay, such royalty payments should not be considered as a lease acquisition cost.

In other words, the royalty payments are simply payments

which any producer must make for the privilege of producing gas regardless of when or how he acquires the leases.

Q. You have mentioned the Louisiana Gas Service Tax. Will you state whether or not you included such tax in your computation of the Rayne Field lease acquisition cost? A. No, I did not include such tax for the same reason that I did not include royalty payments. Namely, I do not consider payment of state taxes as a part of the lease acquisition costs. Louisiana gas severance tax must be paid by all producers of gas and the present tax is in the fixed

amount of 2.3 cents per Mcf, regardless of the amount paid for the leases or the market value of the gas.

Under the provisions of the statute imposing the tax, it will be reduced from 2.3 cents per Mcf to 0.03 cents per Mcf as of June 30, 1964.

Q. I think you misstated yourself. It is 0.3 cents. In other words, three-tenths of a cent per Mcf as of June 1964. A. That is correct.

Q. You stated that the tax is presently in the amount of 2.3 cents per Mcf. Does Texas Eastern pay this tax on the entire production from the Rayne Field? A. Yes, as I previously stated, the amount of tax paid with respect to the royalty gas is deducted from the royalty payments so that the net payment of the tax by Texas Eastern is applicable only to the working interest portion of the gas.

Q. Have you included rate of return to Texas Eastern in your computation of the Rayne Field lease acquisition cost? A. No, because I do not consider rate of return constitutes a part of the lease acquisition costs.

Q. Do you believe Texas Eastern is entitled to earn a reasonable rate of return on its investment in the Rayne Field? A. Yes, but I am not prepared to speculate at this time as to what that return should be. Texas Eastern does not have any rate cases pending at the present time. The rate of return which we might claim with respect to our Rayne Field investment will, of course, necessarily depend upon future circumstances and legal principles in existence if, as and when Texas Eastern may file an application for a rate increase.

Q. Have you ever prepared under your direction a study of the cost to Texas Eastern of producing its own gas? A. Yes, such a study was prepared under my direction in Docket G-12706 and G-18841, which resulted in a unit cost per Mcf of 44.34 cents for company-produced gas.

In addition, in connection with these two dockets, personnel of the Federal Power Commission Staff developed a cost of 23.2781 cents per Mcf for company-produced gas. This does not include gas from the Rayne Field.

Mr. Deakins: I now offer Exhibits X-3 and X-4 and tender

1946

the witness for cross-examination.

Presiding Examiner: The offer will be taken under advisement, Mr. Deakins, to be ruled upon at the conclusion of the cross-examination.

Mr. Deakins: Thank you, Mr. Examiner.

* * * * * * * * * *

2003

Wednesday, November 29, 1961

* * * * * * * * * *

2005

S. P. Osborn

was recalled as a witness, having been previously duly sworn, and testified further as follows:

Presiding Examiner: You have been previously sworn, have you not, Mr. Osborn?

The Witness: Yes, sir.

Direct Examination

By Mr. Deakins:

2006

Q. Have you prepared the back-up data from your working papers which substantiates Exhibit X-4, at the request and instance of the Staff of this Commission? A. I have.

Q. Handing you what has been marked for identification as Exhibits X-8, X-9, X-10, X-11, X-12, X-13, and X-14, will you please state which of those exhibits were the exhibits

about which I just inquired, that is with reference to back-up data? A. Exhibit No. X-8 lists the schedule of activity in the other deferred debit account for the years 1961 through 1989.

Q. Mr. Osborn, you were explaining what exhibit X-8 shows. Will you continue that explanation? A. In Column A, we show the year. In Column B we show the estimated balance in other deferred debits at January 1 of each year. Column C has the amount of note payments in the applicable years.

In Column D shown the amortization of these payments.

Q. Now, referring you to Exhibit X-4, please state what Column of Exhibit X-8 relates to what comparable column of Exhibit X-4, as back-up data? A. Column D of Exhibit X-8—

Q. That is "D" as in "dog"?

2007

A. That is right—is the same as Column "B" in Exhibit X-4.

Q. And the total shown under "Totals" of Column "D" of Exhibit X-8 is the total figure shown on Column "B" of Exhibit X-4, am I correct? A. That is correct.

Q. What was the source of this information? A. The source of this information was based on the schedule of note payments and the estimated schedule of production from the Rayne Field.

Q. Referring you to what is marked for identification as X-9, will you please state by whom that was prepared and what it shows? A. Exhibit X-9 was prepared under my direct supervision and shows the balance included in "gas plant in service," and the related reserves for depreciation, depletion and amortization at December 31, 1960. This was taken from the books and records of Texas Eastern Transmission Corporation.

Q. Please state what columns of Exhibit X-4 are related

to Exhibit X-9. A. Exhibit X-9 relates to Columns "C," "D," and "E" of Exhibit X-4.

Q. You won't find the figures shown on Exhibit X-9 as such, in those columns, isn't that a fact?

2008

A. That is correct.

Q. Am I correct in assuming that those are a part of the figures shown in Columns C, D, and E of Exhibit X-4? A. That is right.

Q. I forgot to ask you this: Who prepared Exhibit X-8? A. X-8 was prepared under my direct supervision.

Q. Referring you to what has been marked for identification as Exhibit X-10, please state by whom that was prepared, and what it purports to show. A. Exhibit X-10 was prepared under my direct supervision and shows the estimated balance of tangible plant, natural gas producing leaseholds, and intangible drilling costs less applicable reserves at January 1 each year for the years 1961 through 1989.

Q. What was the source of the information which is shown on Exhibit X-10? A. Exhibit X-10 is based on the estimated schedule of production of the Rayne Field for years 1961 through 1989.

Q. Now will you please state to what part of Exhibit X-4 the figures shown on X-10 relate? A. The figures shown on X-10 relate to columns C, D, and E of Exhibit X-4.

Q. Is it a fact that as in the case of Exhibit X-9, these figures shown on Exhibit X-10 do not appear in Columns C,

2009

D, and E of Exhibit X-4 as such, but are a part of the figures which make up those three columns? A. That is right.

Q. Referring you to Exhibit X-11 for identification, please state by whom that was prepared and what it purports to show. A. Exhibit X-11 was prepared under my

direct supervision and shows the estimated net liquid revenues for the years 1961 through 1989. Column A of this exhibit shows the year. Column B shows the nonrecoverable operating and maintenance expense for the Rayne Field.

Column C shows the estimated separator liquids revenues. Column D shows the natural gas liquids revenues. Column E shows the net liquids revenues and is the same figure, same total, as shown on Exhibit X-4, Column F.

Q. I notice that there are three footnotes which relate to Columns B, C, and D, of Exhibit X-11. Is it necessary to make any explanation of those footnotes, at this time? A. I do not think so. They are cross-references.

Q. They are self-explanatory? A. That is right.

Q. Did you state the basis of the information on which Exhibit X-11 was prepared and estimated? A. I will. It is based on amounts supplied and shown in

Exhibit X-5.

Q. Did you state, Mr. Osborn, to what column of Exhibit X-4 the figures shown on Exhibit X-11, particularly Column E, relate? A. I indicated that, but I will repeat it.

Q. All right. A. The amounts shown in Column E of Exhibit X-11 are the same as shown in Column F of Exhibit X-4.

Q. Referring you now to what has been marked for identification as Exhibit X-12, please state by whom this was prepared and what it purports to show. A. Exhibit X-12 was prepared under my direct supervision. It is a schedule of Rayne Field note payments, based on production estimated in Exhibit X-2, page 2, of Docket No. G-12446.

Q. That, as I take it, indicates the note payments as they will take place under the estimated schedule of production which has been presented by Texas Eastern in these proceedings, is that right? A. That is correct.

Q. Please state in general terms what Columns B, C, D, E, F, G, H, and I refer to insofar as it pertains to the interests which are covered by the notes? A. Well, it is self-explanatory: The interest of Continental Oil Company, et al, the original sellers, is shown

2011

under Columns B and C, is that correct? A. That is right.

Q. Dishman, et al, what interests are those shown on other exhibits? How are they referred to? A. I believe those interests are referred to in Exhibit X-5.

Q. X-5, and that is true of Kirby and Muller? A. That is right.

Q. As well as Texas Gas? A. That is right.

Q. Referring you to Exhibit X-13 for identification, please state by whom that was prepared, at whose instance, and what it purports to show? A. Exhibit X-13 was prepared under my direct supervision at the request of the Staff of the Federal Power Commission. It shows the schedule of Rayne Field note payments, assuming no accelerated installations, just as stated on the notes.

Q. That is not based upon the estimated schedule of production by Texas Eastern in these proceedings, is it? A. It is not.

Q. We have also had—I don't know whether we have had it marked for identification or not, it is X-14. Do you have a copy of that exhibit before you? A. I have.

Q. Please state by whom that exhibit was prepared.

2012

A. Exhibit X-14 was prepared under my direct supervision.

Q. This exhibit, likewise, was prepared at the request of the Staff of the Federal Power Commission, was it not? A. That is correct.

Q. And prepared as a supplement to Exhibit X-4, is that correct? A. That is right.

Q. State what that exhibit purports to show in addition to the items shown on Exhibit X-4. A. Exhibit X-14 shows the cost of gas as shown in Exhibit X-4, adjusted to include outside interests, as well as the Louisiana severance tax, for the years 1961 through 1989.

Q. The outside interests, does that include royalty interest, as well? A. It does.

Q. On what pressure base is that exhibit prepared? A. On a pressure base of 14.73.

Q. Have you prepared cost of service studies under various assumptions, for illustrative purposes, and with the reservation that they are not binding on Texas Eastern? A. I have prepared four such studies, and submit them for illustrative purposes, only, with the understanding and reservation that they will not be binding upon Texas Eastern

in any future proceedings as to rate-of-return rate base, rate-making principles, estimated costs or for any other purposes.

Q. I hand you what has been marked for the purpose of identification as Exhibit No. X-15. Will you please state by whom that was prepared and what it purports to show. A. Exhibit X-15 was prepared under my direct supervision. It is a cost of service study based upon the following assumptions:

In Column "B," we have taken the total cost of gas as indicated in Column "G" of Exhibit X-4.

Q. That is the same figure that appears on Exhibit X-4? A. That is right. Then to that we have added an assumed rate of return of 6 percent as shown in Column "C."

In Column "D" we have the federal income tax related to the return in Column "C."

Columns "C" and "D" have been added to Column "B" to get an estimated total cost of service.

Column "F" indicates by years at a 14.73 pressure base the average cost of this gas per Mcf.

Column "G" states the average cost on a 15.025 pressure base.

Q. Under the totals in line 31 of Column F and G of Exhibit X-15, are shown the average cost per Mcf, of gas, throughout the years covered by that exhibit at the pressure

2014

bases which I have indicated, is that not right? A. Yes, sir.

Q. At the top of that exhibit that is referred to as Case 1? A. Yes, sir.

Q. Referring you to Case 2, marked for identification as Exhibit No. X-16, please state what that purports to show and how that differs from Case No. 1 as shown by Exhibit X-15? A. Exhibit X-16 again states the total cost of gas contained in Exhibit X-4, Column G, to which has been added in Column C of X-16 the Louisiana severance tax on working interest gas.

Q. How much is that amount per Mcf? A. I don't have the amount per Mcf, but that is the same amount as shown in Exhibit X-14, Column "I."

Mr. Flaningam: Isn't it shown as Footnote 1 on X—

By Mr. Deakins:

Q. Referring you to Footnote 1, Column C, does that have reference to the computation of the Louisiana severance tax? A. That is correct.

Q. And that correctly explains the application of that tax in this column? A. Yes, sir.

Q. All right. Now will you please explain—

2015

A. Excuse me. In addition to the severance tax we have again picked up the return at 6 percent in Column E, and

the related federal income tax, in Column "F," as was shown in Exhibit X-15, Columns S and D.

Column "G" is the total cost of service as indicated under Case 2.

Column "H" is the average cost per Mcf, stated on a 14.73 pressure base.

Column "I" is the average cost per Mcf of gas at a 15.025 pressure base.

Q. Now, Mr. Osborn, referring you to what has been marked for the purpose of identification as Exhibit X-17, which is indicated to be Case 3, in the caption thereof, please state what that purports to show, by whom it was prepared and how it differs from Exhibit X-16. A. Exhibit X-17 again starts in Column "B" with the total cost of gas as indicated in Exhibit X-4, Column "G." To this has been added the Louisiana severance tax on working interest gas, as explained in Exhibit X-16, plus the royalty and outside interest gas in Column "D."

There is a footnote to Column "D"? A. That is right.

Q. What—how did you price the royalty and outside interest gas as shown on that exhibit? A. The royalty and outside interest gas was priced at a

2016

rate of 22.1563 cents per Mcf, which is equivalent to 22.6 cents at a 15.025 pressure base.

Q. I take it the first pressure base was at 14.73 pounds? A. 14.73, that is right.

Q. What is Column "E"? A. Total before return and federal income tax.

Q. What have you added to Column "E"? A. I have added to Column "E" the return at 6 percent and the—in Column F, and in Column G the federal income tax related to such return, as shown on Exhibit X-15, to accumulate a total cost of service in Column H.

Column I is the average cost per Mcf of gas at the 14.73

pressure base, and Column J is the average cost per Mcf of gas at a 15.025 pressure base.

Q. You did not state by whom this was prepared and the source of this information. A. This was prepared under my direct supervision and again is based upon the estimated schedule of production shown in this docket.

Q. Now, referring you to what has been marked for the purposed of identification as Exhibit X-18, referred to in its caption as Case No. 4, please state what that purports to show and how that exhibit differs, and in what respect it differs, from Exhibit X-17. A. Exhibit X-18 was prepared under my direct supervision,

and again it starts in Column B, with the total cost of gas as indicated in Exhibit X-4, Column G.

Q. What have you added to that? A. To that has been added the Louisiana Severance Tax.

Q. Was that one the same basis as you have described in the other exhibits? A. That is correct.

Q. All right. A. Column B is the royalty and outside gas, interest gas, that we have shown on Exhibit X-17, to which has been added in Columns F and G returns at 6 percent, and the related federal income tax.

In addition, in the column between G and H which is marked on Exhibit X-18 as a second colunm F we have computed a return on our "other deferred debit account," the balance in the "other deferred debit account," at 6 percent, and the related federal income tax in column H.

Q. That relates to the addition as shown in Column F, does it not? A. That is correct.

Q. That produced the total cost of service shown in Column I, is that right? A. That is correct.

Q. And thereafter in columns J and K, at the 14.73 and 15.025 pound pressure bases is shown the average cost of gas per Mcf under that assumption, is that correct?

2018

A. Yes, sir.

Q. Mr. Osborn, have you also calculated on an average basis a rate of return of 6.25 percent in lieu of the 6 percent used in the cost of service studies which you have just testified concerning, and which are identified as Exhibits X-15, X-16, X-17, and X-18? A. I have.

Q. State the cost of service per Mcf under that assumption. A. Under that assumption, Exhibit X-15, Column F, at 6.25 percent, the average cost per Mcf would be 18.52.

In Column G, the average cost would be 18.89.

Q. Now referring you to Exhibit X-16. A. Exhibit X-16, Column H, at a rate of return of 6.25 percent, an average cost of gas of 20.77 cents.

Column I, 21.19 cents per Mcf.

Q. Now referring you to Exhibit X-17. A. Exhibit X-17, Column I, the average cost per Mcf would be, at 6.25 percent, 21.04 cents.

Q. What is that cost at 15.025? A. 21.46 cents.

Q. Referring you to Exhibit X-18, please state the cost at the two pressure bases, on the basis of that exhibit. A. Exhibit X-18 at a 6.25 percent rate of return, the average cost per Mcf in Column J would be 24.12 cents and in

2019

Column K, 24.60 cents.

Q. Do you have a formula that can be used to calculate the average cost under both of these bases at other increments? A. I do not have a formula, but the calculation indicates that in Exhibits X-15, X-16, and X-17, for each change of one-quarter percent, it would be approximately 1 mill and for Exhibit X-18 for each change of one-quarter percent in the return, it would be approximately 2.6 mills.

Mr. Flaningam: Would this be a convenient point to ask a clarifying question?

Mr. Deakins: Not quite, Mr. Flaningam.

Mr. Flaningam: All right.

Mr. Deakins: Mr. Examiner, I offer Exhibits X-8, X-9, X-10, X-11, X-12, X-13, X-14, X-15, X-16, X-17, and X-18, and tender the witness.

These are offered subject to the reservation stated by the witness and by Mr. Head yesterday.

Presiding Examiner: The items referred to by counsel for Texas Eastern will be marked for identification as Exhibits X-8 through X-18. The ruling on their admissibility will be reserved until the conclusion of cross examination, as I did with the other exhibits which you have offered.

(The documents referred to were marked exhibits Nos. X-8 through X-18, for identification.)

2022

* * * * * * * *

By Mr. Lewnes:

Q. Is it correct to assume Exhibits X-15 through X-18 are based on the production contemplated in Exhibit X-2? A. That is correct.

Q. On Exhibit X-15 where you have return at 6 percent, to what exhibit and what column can we look to see where you

2023

applied the 6 percent? A. If you will look at Exhibit X-10, sir, Column E, I applied the 6 percent.

Q. Is that the year end or average plant investment? A. This is the year-end, I believe.

Q. And you have not included in the rate base an allowance for materials and supplies or working capital, other than that in Account 186? A. In Exhibit X-15, I have not included any working capital.

Q. But you have included it in some of the other

exhibits? A. No, I have not. X-15, X-16, and X-17 do not. X-18 has the balance in the other deferred debit account.

Q. In other words, you have not included materials and supplies or other working capital? A. That is correct.

Q. Referring to Exhibit X-13, am I correct that these are non-interest-bearing notes? A. That is right.

Q. In order to fully understand this, we have to go one step further, I think. Could you indicate what are the volumes of gas stated in the notes that would trigger the preceding notes and cause acceleration? Not the volumes you have taken which then triggers the notes, but

2024

what is the maximum volume you can take under the note payments before it would trigger another note? A. Under the notes with Continental Oil, Sun Oil, General Crude and Marr, the total allowable production for the 12 months ending August 1 of 1960 and August 1 of 1961 we were allowed annually, without triggering the notes, was 31,656,524 Mcf.

Subsequent to August 1, 1961, and each year thereafter, we were allowed 40,331,631 Mcf. The volume of gas, —and this is a cumulative figure—if we exceeded the accumulation under these four instances by 3,360,969 Mcf, we would trigger an installment of the note.

Mr. Flaningam: What was the last figure you mentioned?

The Witness: 3,360,969 Mcf.

Mr. Flaningam: Thank you.

The Witness: In the Dishman transaction for the first two 12-months periods, the volume of gas was 276,360 Mcf. For the periods subsequent to August 1, 1961, the volume is 352,093 Mcf. The amount required to trigger an installment of the note in excess of an accumulation is 23,341 Mcf.

By Mr. Lewnes:

Q. That is in any given year after 1961? A. If your accumulation exceeded it.

Q. That accumulation can build up all the way through

2025

1975? A. That is right. The comparable figures for the Kirby interest for the first two years is 173,367 Mcf. For the subsequent years, it is 223,424 Mcf.

The volume required to trigger an installment is 18,618 Mcf.

For the Muller interests for the first two years, the volume is 345,695 Mcf. For the subsequent years 440,429 Mcf. The volume required to trigger an installment is 36,702 Mcf.

Texas Gas interests, for the first two years, it is 8,438 Mcf, for the subsequent years 10,750 Mcf. The amount, the volume, required to trigger an installment is 896 Mcf.

Q. Are these figures set forth in the notes, or is the some private understanding between the companies? A. I believe it is set forth in the notes.

Mr. Head: That is correct.

By Mr. Lewnes:

Q. When you referred to the gas, the gas volumes, are you referring to residue gas or pipeline gas, or are the terms synonymous? A. We have related it here to our estimated schedule of production.

Q. As contained in Exhibit X-2? A. That is right.

Q. If I take your Exhibit X-14 and add to it return at 6 percent both on net plant and other deferred debit

2026

account, plus the federal income tax return on both, would I get the results shown in Exhibit X-18? A. Yes, sir, you should.

Mr. Lewnes: Thank you. We have no further questions at this time.

Mr. Kirby: Could we have a definition of "other outside interest"? There is a title on Exhibit 14 that says "includes other outside interest gas." I don't believe that has been defined.

The Witness: That includes the royalty gas plus a very small fraction of a percentage of a minority interest, very small. For all practical purposes, this is royalty gas.

* * * * * * * *

2028

John P. Furman

was recalled as a witness, and having been previously duly sworn, testified as follows:

Presiding Examiner: Mr. Furman, you have previously been sworn and testified in this proceeding?

The Witness: That is correct, sir.

Direct Examination

By Mr. Deakins:

Q. Referring you to a document which you have before you, which has been marked "Exhibit X-6, Schedule 9 Revised," please state what that is and by whom it was prepared. A. That is a revision of Schedule 9 which was included in my original exhibit. It was prepared under my supervision and direction.

Q. Mrs. Suchow pointed out an error in that exhibit at the earlier phase of this proceeding, did she not? A. That is right.

Q. You corrected it, I understand, took that error out, removed that error. Does the omission of those three items to which you referred affect your testimony? A.

Several changes are required in my answer to his questions on page 1845 of the transcript.

Q. State what those are. A. At lines 7 and 8, I stated that the schedule showed

2029

20 instances in which certificates have been issued to producers at initial base prices of 21.5 cents. The number 20 should be changed to 18, and in line 9, 28 should be changed to 26.

Q. That is the number 28 should be changed to 26? A. Correct. At lines 18 through 21, I stated that the schedule showed 50 instances in which the average base price is 23 cents or more, and 31 instances in which the average base price is 25 cents or more. The number 50 should be changed to 47, on lines 18 and 23. The number 31 should be changed to 28 on line 19.

Q. On page 1846 of the transcript you answered several questions concerning the volumes shown in Column (i) of Schedule 9. What changes should be made in the volumes you gave there? A. On line 18, 441,637 Mcf should be changed to 423,031 MMcf.

On line 22, 362,500 MMcf should be changed to 343,873 MMcf. The answer beginning at line 4 on page 1847 should read, "on that assumption the reserves represented by such permanently certificated sales would be 6,877,000 MMcf, or just under 7 trillion cubic feet.

Mr. Deakins: Mr. Examiner, I now offer Exhibit X-6 and Schedule 9 thereof as revised, and tender this witness for cross examination.

2030

Presiding Examiner: Off the record.

(Discussion off the record.)

(2030)

Presiding Examiner: On the record.

Mr. Deakins: Mr. Examiner, in connection with that offer, I should like to withdraw Schedule 9 of Exhibit X-6 as originally tendered and offer in its place Revised Schedule 9 of Exhibit X-6 to which this testimony this morning has referred.

Presiding Examiner: Exhibit No. X-6 was previously offered on October 23 and the offer was then taken under advisement pending cross examination. Texas Eastern may now withdraw its Schedule No. 9 to that exhibit and substitute in lieu thereof a revised Schedule 9. The reservation on the admissibility will stand until completion of cross examination of this witness.

* * * * * * * *

2124

Monday, December 4, 1961.

* * * * * * * *

2131

John P. Jacobs

recalled as a witness and, having been previously sworn, was examined and testified as follows:

CROSS EXAMINATION

By MR. LEWNES:

* * * * * * * *

2133

A. Yes. The Management Agreement which is marked Exhibit X-19 sets forth the entire transaction by which Texas Eastern contracted with Continental to act as operator of the wells at Rayne Field.

* * * * * * * *

2134

Q. Could you elaborate as to what is the full consideration upon which this Operating Agreement was negotiated? A. First, the consideration to Texas Eastern was this: We were purchasing a property which represented an important adjunct to our gas supply. The wells from which gas is produced from this property are deep, and the reservoirs in this property are under high pressure. We thought it would be in the public interest to retain as Operator of these wells the one organization in the world that knew the most about them.

That was the Continental Oil Company which had supervised the drilling and completion of all the Rayne Field Wells.

Consequently, we entered into the Management Agreement.

Now, in return for Continental's operating these wells for Texas Eastern, Continental receives a consideration which is paid monthly which roughly amounts to two items: One, a reimbursement for all direct expenses; secondly, a payment for what might be considered overhead and general expense.

Now, the overhead item breaks down roughly into three items: First, $75 per well per month for each well that is

2135

producing; secondly, $500 per month for any well that is drilling; thirdly, a management fee of $4000 per month.

Now, the $4000 item is termed, and properly so, in the management agreement as a management fee. If you had to do any further explanation of its nature, it is a compensation to Continental for its expertise that it has developed in discovering and drilling the wells in this field.

(2135)

You might also say that it is an item that covers an allocable share of Continental's main office expense, the main office time that is spent in directing the operation of the Rayne Field Wells.

Q. Then would you say that exclusive of the $4000, Continental will operate Rayne Field for Texas Eastern at cost? A. I would agree that the consideration to Continental in this Management Agreement certainly approximates its actual expenditures in the operation of the field.

Q. Has this $4000 monthly payment to Continental been included in any of your costs on Exhibit X-5? A. Yes. The $4000 per month item is included in the figures set forth on page 8 of Exhibit X-5 on which page are set forth the estimated well operating and maintenance expenses for Rayne Field for the future life of the field.

Now, as I testified, those figures are developed from Texas Eastern's own experience between July 27, 1959 and

2136

July 1, 1961.

Now, by Texas Eastern's own experience, I mean that we took from our own books the figures representing the amounts that had been paid to Continental under the Management Agreement. We took from our own books any other expenses that were associated with Rayne Field. And we averaged those over the period of time and rounded it off to the $1500 per month per well completion figure that is represented by page 8 of Exhibit X-5.

Q. In other words, these were the costs incurred by Continental for operating Rayne Field which it submitted to Texas as Eastern upon which Texas Eastern reimbursed them, and then you took these as a basis for determining what your future costs would be? A. The costs shown—or the cost that served as a basis of the figures set out on page 8 did include all of the payments

that Texas Eastern had made to Continental under the Management Agreement plus some other expenses.

And those payments to Continental did include the $4000 per month item.

Q. Now, Mr. Jacobs, this may sound elemental. But I should like to start at the wellhead and follow the physical course of the gas. Let's start with the first step.

Am I correct that once the gas leaves the wellhead, the first stop is at the separators; is that correct?

2137

A. That is correct. If you would like, Mr. Lewnes, I could put on the record the description you have asked for.

When I get through if you have some questions about things I haven't made plain, I will answer those.

Q. What I would like to do is have you proceed, and if I may interrupt you at certain stages and ask you to clarify each particular stage? A. Certainly.

The gas moves from the reservoir to the wellhead in the wells which are operated by Continental under the Management Agreement. The gas is turned over to Texas Eastern at the first control point which is at the wellhead and moves in an individual line for each of the wells to a central separator station which is located at a central point in the field adjacent to the LaGloria Processing Plant.

At this central separation station, the gas from the wells or from each well first goes through an ordinary mechanical separator which at the present time operates at about 3000 pounds. Liquid is taken from the bottom of the separator—and we will come back in a minute and pick up that 3000 pound liquid stream—the gas of the individual separators is metered off the separator. The gas off of the several individual separators is then comingled and put through low temperature separators which are operated just ahead of the

2138

gas processing plant.

Now, these low temperature separators which operate at pressures in the order of magnitude of, oh, 1,050 pounds also have a liquid stream taken off the bottom of them. The liquid off of the 3000 pound separators and the liquid off of the low temperature separators is mixed together. And that stream is the stream that we call separator liquids.

Q. Mr. Jacobs, did you state that the gas is metered before it goes into the 3000 pound separator individually? A. No. It is metered as it comes out of the individual 3000 pound separators before it is comingled.

Q. All right. Now, could you state the physical disposition of this liquid? A. The liquid from the 3000 pound separators and the low temperature separators is comingled. And the comingled liquid is fed to a stabilizer tower which is a part of our natural gasoline plant operation.

Q. When you say "our", are you referring to Texas Eastern or Louisiana Gas? A. Excuse me. By "our" I was thinking of the whole Rayne Field Operating set-up. I meant the LaGloria processing plant at Rayne Field. The stabilizer tower is actually a part of the processing plant.

In the stabilizer tower, the lighter ends, propane,

2139

butane gasoline which would normally be lost off of storage tanks is separated from the separator liquids and fed into the gasoline plant operation. The separator liquids off of the stabilizer tower which operates at a pressure of about 150 pounds go to tankage.

Q. How is that disposed of? A. The separator liquids in tankage are, of course, owned by Texas Eastern. The

separator liquids are sold in the tanks under long-term contracts in two principals groups. One part of the separator liquids is sold to Continental Oil Company, again under a long-term contract. Continental moves the separator liquids by pipeline to its Lake Charles Refinery for its operation theres.

Q. Excuse me. At this point: is there an existing long-term contract with Continental for the sale of these liquids? A. There is an existing long-term contract between Texas Eastern and Continental for the sale of these separator liquids.

Now, the other part of the separator liquids in the tanks —and this is roughly a 50-50 split—is sold to Sun Oil Company and others under a long-term contract and is moved by pipeline to an upgrading plant in Acadia Parish, Louisiana which is operated by an organization called "Acadia Corporation,"

2140

Now, if I might interject one thing, Mr. Lewnes, before your next question. The stabilization of condensate at Rayne Field is a definite conservation device which was possible because we bought the whole field. Approximately 1 percent—and this is a very rough figure—but approximately 1 percent of the Rayne Field gas would be lost out of tankage if we didn't have the stabilization.

Now, by means of the stabilization this 1 percent of the gas is conserved and ends up in our pipeline.

I might further add that that 1 percent factor hasn't exactly been taken into account in all the calculations that we have presented here. It is a plus factor insofar as our volumes of residue gas are concerned.

Q. What is the contract price that you have with Continental and that you have with Sun Oil for the sale of the tank liquids which you have stated are Texas East-

ern's property? A. The contract price set forth in those contracts in effect is the day-to-day posted price either at Rayne Field or in the area.

Q. You mentioned that these are long-term contracts. When do the contracts terminate? Do you have that date? A. These contracts will terminate at the time the production payments retained by Continental and others under the assignment and conveyance terminate.

2141

Q. To whom will Texas Eastern then sell the tank liquids, assuming there are tank liquids after production payments, to whom would Texas Eastern sell those? A. We will have at that time a wide range of choices, Mr. Lewnes. Actually with the pipelines in existence I should think that our buyers that would offer the most, if you will, would be the people that are presently buying the liquids.

We are fortunate that Rayne Field is located in an area that is served by pipelines that gather high gravity products in the field. And there are many other buyers in the area.

For example, Gulf, Humble, and Texaco have maintained posted prices for Rayne Field Condensate—strike the word "condensate"—Rayne Field separator liquids, since the beginning of Rayne Field.

Q. At this point you have mentioned these tank liquids are Texas Eastern's property. Am I correct in assuming that Texas Eastern is not paying anything for these liquids other than as is reflected in the note payment?

In other words, there isn't anything over and above the note payments that Texas Eastern now must pay for these liquids? A. There is nothing over and above the cash downpayment, the note payments, that Texas Eastern must pay

2142

for these liquids.

Q. You referred to LaGloria. Could you elaborate a little as to what LaGloria is and who it is owned by? A. LaGloria Oil and Gas Corporation is one of the larger gas processors in the Gulf Coast area, and also one of the older of the Gulf Coast area gas processors. I believe —and this is subject to correction—but I believe that all of the stock of LaGloria Oil and Gas Corporation is owned by Texas Eastern Transmission Corporation.

Q. Do you know what the capacity of the LaGloria Plant is? A. Yes. In the design of the plant, we contracted that LaGloria would install a plant with an absorber capacity of 176 million cubic feet per day maximum.

Actually, as our record shows here, we have processed as much as 182 million cubic feet per day of residue gas; and we really don't know just exactly what the plant actually would pass.

Q. All right. Now, let's assume that the Texas Eastern has now sold the liquids to Continental and Sun Oil. How does it dispose of the revenues? A. From the fund of money that Texas Eastern gets from the sale of the separator liquids, Texas Eastern deducts all the expenses of operating the field in accordance with the provisions of the assignment and conveyance.

2143

Now, generally any out-of-pocket payment that Texas Eastern makes is reimbursible. All expenses under the management agreement are reimbursible. Texas Eastern's expenses in connection with operating and maintaining the gathering lines in the separator or station are reimbursible. Delay rentals or shut-in rentals, things like

payments of that type that are due under the leases are reimbursible.

So, the net effect of the separator liquids production payment is that the liquids at Rayne Field bear all the operating expenses of the field.

Q. Well —— A. Excuse me, Mr. Lewnes, let me finish my statement.

Q. I am sorry. A. That is, after Texas Eastern has kept back out of the amounts received from the sale of separator liquids the field operating expenses which I have described and which are set forth in the assignment and conveyance, then the monies that are left over are paid each month in certain percentages to Continental, et al., as the retained production payment which again is described in the assignment and conveyance.

Q. You say Continental, et al. What about Dishman, Muller, Texas Gas? A. The same thing applies there. As I testified before, in connection with these smaller interests we

2144

duplicated the deal that we had made with Continental on the basis of the reserve interest that was owned by a group like the Dishman Group.

At the same time—and this goes back to a question I think Mr. Flanningam asked a while ago—we expanded the Management Agreement to be sure that there wasn't any question about this little interest being covered by the Management Agreement.

Mr. Flanningam: I was going to ask when you spoke of the assignment and conveyance, in the context it appeared to refer to Continental. But actually there are five of them, are there not; in a sense they are identical except as to the difference in the respective interests of the several groups?

The Witness: All of the assignments and conveyances

that apply to Rayne Field are identical in form with the exception that the names of the parties are different, and the dollar considerations which may be set forth are different.

By Mr. Lewnes:

Q. Again, in other words, if I follow the mechanics of this properly, Texas Eastern will receive dollars for the sale of these liquids? Now, they will take those dollars and retain them. Continental then will submit to Texas Eastern monthly statements as to its costs, and Texas Eastern will reimburse it for its costs. Additionally Texas Eastern will then subtract from these dollars the other costs which you

2145

mentioned. And the monies that are then left are turned over to Continental and the other producer-sellers? A. I would answer your question yes, Mr. Lewnes, if you mean by Continental's costs it is right—or the dollars it has a right to be paid by Texas Eastern under the Management Agreement.

Q. Yes, precisely.

And when does this production payment terminate? A. Roughly in 1975.

Q. How was that date arrived at?

We are again assuming, are we not, that there will be liquids to be derived from this gas subsequent to that date? A. In very substantial quantities as we have shown in some of our exhibits here, yes; that is, the so-called—or that is the liquid production after the production payments terminate we think is one of the advantages to the consumer that we have built in the transaction that we have made here at Rayne Field.

Mr. Deakins: Are you talking about the natural gas consumer?

(2145)

The Witness: Yes, the Natural Gas Consumer; Texas Eastern's customers.

Mr. Lownes, it would be a very difficult thing to say why that date was set at 1975 and not some other date. For all reasonable purposes the production payments and the note

2146

payments that we have set up are coexistent; that is, the production payment will terminate at the time the last notes are paid.

* * * * * * * *

2245

Tuesday, December 5, 1961.

* * * * * * * *

2257

John P. Jacobs

In the year 1957, at a cost of $101,100, Continental worked over the W. Petitjean, Unit 1, No. 1 well, in order to complete the well which had previously produced from the Homeseekers C oil sand to the Klumpp D gas reservoir.

By Mr. Flaningam:

Q. On page 4 of your Exhibit 5 you have shown estimated tubing replacement costs, have you not? A. That is correct.

Q. Has the tubing in any of the wells in the Rayne field been replaced, Mr. Jacobs? A. Yes, there have been some tubing replacements prior to the time that Texas Eastern took over the field, in July, or all on July 27, 1959. There have not been any tubing replacements since Texas Eastern took over the field.

* * * * * * * *

2304

E. A. Olson

was recalled as a witness and, having been previously duly sworn, was examined and testified further as follows:

Presiding Examiner: You previously testified, haven't you?

The Witness: Yes.

Presiding Examiner: Sit right down.

Are you going to lead off, Mr. Lewnes?

Mr. Lewnes: Yes, sir. If there is no additional direct, we will proceed with cross-examination.

Cross-Examination

By Mr. Lewnes:

* * * * * * * *

2308

Q. Now, in addition to a reserve estimate which you have stated you prepared in 1957, it is a fact, is it not, that you also prepared one as of January 1, 1959—isn't that correct? A. Yes, sir.

Q. And both of those estimates, both the '57 estimate and the '59 estimate, have been submitted as evidence in these proceedings, isn't that correct? A. That is correct, yes, sir.

Q. Now, at transcript page 1811 and 1812 you state that the four additional wells drilled since 1959 have not materially changed the field.

Now, when you say have not materially changed the field, are you referring to the reserves? A. Yes, I was referring to the report made in 1959 and this report made as of 1-1-61, that these four wells had been drilled during that interval of time, and that they did not materially change the reserve picture.

(2308)

Q. Now, you go on to state in your direct that these wells have proved up additional reservoirs, is that correct? A. Yes, sir.

Q. Now, do you have your 1959 reserve estimate, which is Exhibit B-13, with you? A. I believe I do, yes.

2309

Q. How many reservoirs do you show in that exhibit? A. In the 1959 exhibit, I show five reservoirs, one of which is split up into two different segments.

Q. But it is five reservoirs? A. Yes, sir.

Q. And what is the initial gas in place as shown on that exhibit? A. The initial gas in place as shown on the 1959 exhibit is 1,218,821 MMcf.

Q. Now, in your present exhibit, which has been identified as X-2, you show 7 reservoirs, isn't that correct? A. That is correct.

Q. And what is the initial gas in place which you show on this present exhibit X-2? A. The initial gas in place on the 1961 exhibit is 1,183,517 MMcf.

Q. Now, could you explain why your initial gas in place has decreased since 1959? A. Well, for one reason because of the drilling of these additional wells, it changed the interpretation somewhat of the fault picture of the field and as a result some of the reservoirs became a slight bit smaller, whereas these other two new reservoirs were included in this exhibit and they were not included in the 1959 exhibit.

Q. So what you are stating in effect, is, are you not,

2310

that the additional drilling has resulted in a decrease of gas reserves—isn't that correct? A. There was a small decrease, if you compare these two figures, yes, sir.

Q. Will you look at transcript page 1898, to the testimony of Mr. Jacobs.

Now, at the top of that page, Mr. Jacobs states, "While it is, of course, not exact as to what will be the future history of the field, there is also the definite possibility of future discoveries and production history which increases the gas reserves and at the same time decrease the net cost per Mcf of gas produced from Rayne field."

The present history of the development of this field has proved to the contrary of what Mr. Jacobs has stated, hasn't it? A. Only to a certain degree. As to these two figures which you asked me to read, the possibility of additional sands that have not been tested in this field are still very good, and as a result it is quite possible that reserves of this field will be larger than we are showing at the present time, as of 1-1-61.

Q. Now, is it not a fact that the north segment of the Nodasaria A sand as shown on your exhibits in 1959 and 1961 reflects a decrease of reserves in the nature of 100 billion cubic feet?

2311

A. That is correct.

Q. Would you say that this is approximately a reduction of 10 percent of the original reserves in place for this field? A. I haven't exactly figured out what the difference between the two figures which you asked me to give in place is. If you say 10 percent, I will take that subject to check.

Q. Now, what has caused such a large reduction for one particular segment, the north segment of the Nodasaria sand? A. That was entirely due to a fault. If you will refer to the last map in Exhibit X-2 and also the last map in the 1959 exhibit.

Let us first take the 1959 exhibit. You will notice the line just below the well that is called Continental Castille

et al No. 1. There is a solid line going in more or less generally east-west direction, which signifies one of the major faults in the area.

That same fault now: Due to the additional drilling that has come in since 1959, it was now determined that that fault went more in a northwest-southeast direction than the east-west direction that I show in 1959. That is one of the differences that we discovered on the fault interpretation for this field due to the additional drilling.

2312

There is another fault. The topmost solid line in my 1959 exhibit is another major fault in the field. And due to the additional drilling between 59 and 61, that fault was found to be further south than we had shown it in our 1959 exhibit.

Now, the combination of these two changes in fault interpretation, due to the additional drilling, reduced the size of the north segment of the Nodasaria A sand.

Q. And you attribute this change or this re-evaluation of where the fault lines were as the only reason why the Nodasaria reserves in the north segment have been reduced? A. That is correct.

And then you will notice also that as a result of the Nodasaria A north segment becoming smaller, the Nodasaria A south segment became larger because of the difference, in the change of the fault interpretation.

Q. But the other segment which you say became larger did not become larger in the same proportion as the north segment A became smaller, isn't that correct? A. No, it did not become the same proportion, that is correct.

Q. Now, regarding the fault lines which you showed in your 1959 exhibit, how many control points, and what were they, in regards to both faults? A. If I can remember correctly, we had possibly only

2313

one or two control points on the northmost fault, and at the drilling of the Navarro 1-A well—after the drilling of the Navarro A-1 well ——

Q. Excuse me. Is that indicated on your 1959 exhibit? A. No, sir, it is not.

After the drilling of the Navarro A-1 well, this fault was able to be tied down in a much better fashion than we were able to tie it down in 1959.

Q. Well, what controls did you have in 1959 when you first indicated where the fault line was in your 1959 exhibit? A. I believe the only control we had for that fault was in the Touchet No. 1 well.

Q. Is that indicated? A. Touchet No. 1 well is the northernmost well on the map.

Q. While we are identifying wells, can you tell me whether or not that Continental Castille, and then it is ETUX, well — is that a dry hole? A. That well in that particular location was never drilled.

Q. Now, Mr. Olson, don't you consider a reduction of 100 billion in reserves in the Rayne field a material change?

• • • • • • • •

2314

The Witness: If you compare your two figures that you asked me to read out, of the in place gas, at 1 million 2 in one case and 1 million 183 in another case, I would say there was no real material change.

By Mr. Lewnes:

Q. Well, the 1 million 183 that you referred to includes two additional reservoirs, does it not? A. Well, what difference does that have to do in the material change.

(2314)

Q. Well, we are talking about a decrease in the Nodasaria, of 100 billion cubic feet between 1959, your estimate in 1959 and 1961 and I merely ask whether that is

2315

or is not a material change of reserves for one particular segment in the Rayne field. A. I believe if you add up the entire reservoir, there is probably only about 80 billion, instead of this 100 billion you are talking about.

2316

Q. Well, irrespective of whether we use 80 billion—for the moment, let's use 80 billion. Is 80 billion a material change? A. Yes, I would say it is.

Q. Now, at transcript page 1455—that was your testimony in connection with what we refer to as the 1959 hearing. A. Yes.

Q. Do they have it?

Mr. Head: We don't have it.

By Mr. Lewnes:

Q. You stated in response to a question —— A. I thought I had it, but I don't find it.

Q. ——in response to a question——this was a question that was put to you.

The question: "So that there is a possibility here that there might be a substantially greater reserve in this field than you have told us about.

"Answer: Yes, there are several sands present here now that I actually think there is gas present in them, but they have never been proved up by test."

Right here. A. Yes.

Q. Now, from your testimony up to this point in regards to your present exhibits as they relate to your 1959 exhibits,

2317

again isn't it a fact that additional drilling has actually decreased the reserves?

Mr. Deakins: You mean in total reserves or reserves in the sand, or what are you referring to?

Mr. Lewnes: Total reserves.

The Witness: In some cases it has, and in some cases it hasn't.

By Mr. Lewnes:

Q. Well, we are talking about the overall reserves of Rayne field, the total reserves of Rayne field. A. Well, referring again back to this in place gas figure which I gave in both cases, I would have to say yes, it has reduced it somewhat.

Q. Now, at transcript page 1814, you have stated that you used the volumetric method in estimating the reserves shown in Exhibit X-2. Now, are there other methods of estimating reserves other than the volumetric method? A. Yes, there are.

Q. Could you just indicate the names under which they go? A. Well, you can estimate gas reserves depending upon the amount of history you have and the amount of production that has come out of the wells. You might want to estimate them on the pressure cumulative method.

Q. They are the only methods that you mentioned?

2318

Are there any others that you may know of? A. Those, the volumetric and pressure cumulative methods, are the two methods that are used most often.

Q. Since this field has produced for several years, could you have used this pressure cumulative—I presume that is the same as pressure decline. Could you have used that method? A. I did not choose to use that method.

for the preparing of this exhibit mainly because even though the field has been produced for several years there has been approximately only 7½ percent production of the entire field thus far, according to my reserves. And with only that amount of production history behind a field of this size it would be more appropriate and more reasonable to use the volumetric method than to attempt to put much faith in the pressure decline method as you spoke of.

Q. Pressure decline is the same as the pressure cumulative method? A. Yes.

Q. Now, at transcript page 1815, I believe you have made the assumption that the Rayne field will be depleted through pressure depletion. Now, would you elaborate on the use of the term "pressure depletion"? A. Due to the abnormal pressures which we have present here in this field, we feel through the experience that we

2319

have had that a field of this nature will be depleted by the pressure actually decreasing and not, say, by water encroaching and be flooded out by water drive.

Q. Is water drive the only other method of type of depletion? That is, you have either water drive or pressure depletion? There is no other form? A. No.

Q. Now, will you please turn to your maps in Exhibit X-2. Turn to the first one, if you will.

Will you please indicate and explain the various symbols and lines as they appear on there? A. Well, to start with, the heavy shaded end line that encompasses most of the page is the area that has been dedicated or conveyed to Texas Eastern in this particular purchase. The various dashed lines and solid lines and dash and dot lines represent the productive limits of the various reservoirs

that I show on the map. In this particular case we show four different reservoirs on this particular map.

The light solid lines are lease lines.

You want to get into symbols, too?

Q. Yes, please. A. The various symbols that show the round circle with the marks around the circle are noted as gas wells. There is one well in the approximate center of the field that

you will notice is completely just a heavy dot, called the Continental Mouton No. 2. It designates an oil well.

Q. Mr. Olson, which reservoir is that oil well in? A. I believe it is in the reservoir called Homeseekers C sand.

Now, there is a mistake here on this map where we show a filled-in heavy line, also with hash marks on it, known as the Continental Petitjean No. 1. And that should not have been colored in dark. It should have been —it should look exactly like the other gas symbols that we show on the other wells.

I believe that is all, other than the bayou that is shown there on the map in the northwest part of the field.

Q. And your explanation of the symbols and lines as they appear on your first map are equally applicable to the symbols appearing on your second map; is that correct? A. That is correct.

I should further add that I did not bring out the fault limitations. In other words, the productive limit line of the reservoir could not only—could be a combination of either a shale outline, a fault line, or actually a gas-water contact line.

Presiding Examiner: Let me ask you, on this second map.

The Witness: Yes, sir.

2321

Presiding Examiner: Continental Petitjean No. 1, that you described the symbol on the first map as being a gas producer.

The Witness: Yes.

Presiding Examiner: You said the inside of the circle should not have been shaded out?

Then over the second map you show that same hole as an oil well.

The Witness: That is right, sir. It used to be an oil well, but is no longer an oil well.

Mr. Flaningam: May I ask a clarifying question?

Mr. Lewnes: Yes, sir.

By Mr. Flaningam:

Q. You have referred to symbols for gas wells, circles with hash marks. I notice that some have eight hash marks and some have four. Would you indicate the difference? A. I believe we will have to talk to the draftsman about that. That is just something that he either failed—there is no particular specified number of hash marks that you have to have signifying a gas well. Some people would use eight and some may use six. It just depends on what the draftsman wants to use in a particular way.

Q. Well, take the first map in the upper lefthand portion. You have an item designated "Sun, NOD," and then "UN-10." Does that indicate a dry hole?

2322

A. That is a dry hole symbol. That only has four hash marks, that is correct.

Q. What was the point I was making. A. In other

words, we always put in more hash marks than four on a gas well, but it could vary.

Q. That is it.

By Mr. Lewnes:

Q. Mr. Olson, have you included on your maps 1 and 2 all the existing wells on the Rayne field, properties conveyed to Texas Eastern? A. I believe that there are one or two cases where there are one or two additional wells that are not present on one of the maps that are present on the other. That was an oversight on our part, except where those cases exist where we say we would not have two more wells on one map and would have it on the map, and it is mainly because the reservoirs we show on that map are the only ones they are productive in and they would not be productive on the other reservoirs on the other map.

Q. In response to an inquiry by the Examiner, you stated that Continental Petitjean well on your map No. 2 had been an oil well. Could you state from what reservoir that had produced oil? A. I believe that was in the same reservoir that the other oil well that I had mentioned was in.

2323

Q. That is Homeseekers C Sand? A. Yes.

Q. Will you refer to Exhibit X-21, please, the last page.

Mr. Deakins: I don't think he has that.

The Witness: Yes, sir; I have that.

Mr. Deakins: Do you?

The Witness: I believe so.

By Mr. Lewnes:

Q. Specific reference is made to an item which appears as footnotes 2 and 3. Now, footnote 2 says "Produced

Nodasaria sand from May, 1955, through October, 1956." And that I think refers to the Petitjean No. 1. Could you state why that ceased to produce? A. I believe it refers to the Arceneaux No. 1.

Q. If you say so. A. Would you read that? I didn't quite remember what the question was, again.

Presiding Examiner: Read the question, Mr. Reporter.

(Question read.)

The Witness: It did not exactly cease to produce. Generally speaking, the well was still capable of producing in the Nodasaria sand. However, it was deemed advisable by the operator to work that well over from the Nodasaria to the Klumpp reservoir.

2324

Q. Well, did that well first begin to produce in 1955, in May, 1955? Is that when production commenced from that well? A. If it says here on this sheet, I presume so; yes, sir.

Q. In other words, there was a workover somewhat within a one-year period. Now, do you know what the workover consisted of? A. Well, the workover consisted of changing this well from the Nodasaria sand into the Klumpp reservoir.

Q. What was the reason for that, do you know? A. I would imagine the reason for that would be as these wells were drilled in the field the operator found that he had more wells than he needed in the Nodasaria sand and did not have a balance of wells producing from other reservoirs, and also due to the unitizing or making the various sand units that the State forced or asked the operator to make. All these reasons combined were used, and that was the reason for changing some of the wells from one reservoir to another.

Q. Now, could you give, without my asking the specific questions, give a similar explanation as to footnote 3, which reads, "Produced from the Nodasaria sand from November, 1954, through March, 1955." A. The same reason would apply to that particular well

2325

as I have given for the footnote No. 2 well.

Q. And, finally, getting down to footnote No. 9, which states "This well produced from the Homeseekers C sand from December, 1953, through November, 1957"—could you give us the same explanation for that? A. That well was originally an oil well in the Homeseekers C Sand, and it depleted out of that sand, and after its depletion it was worked over then into the Klumpp gas reservoir.

Q. Am I correct that you have not indicated any dry holes on your maps 1 and 2? A. I believe Mr. Flaningam brought out the dry hole that I failed to mention, in the northwest part of the field known as the Sun Nodasaria unit 10.

Q. Was that or is that the only dry hole drilled on the Rayne field properties, being conveyed to Texas Eastern? A. That is correct.

Q. Are any of the productive limit lines shown on your maps 1 and 2 also the gas-water contact lines? A. Yes, sir; I stated that it was a combination of gas-water contact lines and fault trace or shale outline.

Q. Could you state which reservoirs have a gas-water contact? A. Yes, sir. Gas-water contacts are found in the Nodasaria reservoir, the Homeseekers E reservoir, the Home-

2326

seekers D-2, and the Klumpp D reservoir.

Q. Now, are all—is there a gas-water contact for every well in every one of these reservoirs which you have indi-

cated has a gas-water contact? A. May I have that read back, please?

Presiding Examiner: Yes, will you read the question, Mr. Reporter.

(Question read.)

The Witness: No, sir.

By Mr. Lewnes:

Q. Mr. Olson, in the preparation of your estimates going back from the 1957 estimate all the way up through your present estimate, could you state where you obtained the information upon which these estimates are based; that is, the backup data for them? A. The information was—in the early 1957 estimate part of the information was obtained from the Continental Oil Company. Part of the information from Texas Eastern, and part of the information which we have in our own files. This estimate as of 1/1/61, the information was obtained from Texas Eastern and from our own files.

Q. Well, did you obtain any information from the Louisiana Conservation Commission? A. We used some information from that source; yes, sir.

2327

Q. And, to the best of your knowledge, has all the information that you used to make your reserve estimate —has that been made available to the Staff of this Commission? A. To the best of my knowledge, everything that I used in preparing my estimate has been made available to the Staff.

Q. Now, some of this information that you made available to the Staff was logs. Could you state the purposes for the running of logs. A. Well, in order for you to know you have anything under the ground at all you have to

have an electric log to indicate whether you have any productive reservoirs. It also is used to determine the depth of the reservoir. It is used to obtain net pay of the particular sand you are interested in. It is used to obtain gas-water contacts if present. And can be used for several other things that I just can't think of at the moment.

Q. Can you tell from an electric log whether a reservoir is productive? A. No, you can't.

Q. When you referred to electric logs, did this encompass the different types of electric logs, that is, a micrology, etc.? A. I don't quite get the question.

Presiding Examiner: Will you read the question back,

2328

please?

Mr. Deakins: Read that back.

(Question read.)

The Witness: I was referring mainly to just the plain electric log at that time.

Mr. Lewnes: Right.

By Mr. Lewnes:

Q. Now, there is such a log as a micrology, is there not? A. Yes, sir.

Q. And what is the purpose of a micrology? A. The main purpose of the micrology is to determine the porous sections of the particular sand or reservoir.

Q. Now, what is the purpose of taking cores, conventional cores? A. Cores are normally taken in order to determine the porosity of the formation, and also the permeability.

Q. Isn't it also a fact that you take cores to determine whether you have gas or oil? A. Yes, that is true. You analyze the core to determine whether it is oil saturated or whether it is saturated with gas. You also use a

core in the laboratory to determine interstitial water percentages.

Q. Can you tell whether you have gas or oil by merely looking at a log, an electric log?

2329

A. You can normally tell by the resistive part of the log whether some form of hydrocarbons are present, yes. Actually, there is only one method to tell whether there is definitely gas or definitely oil, and that is to perforate it and see what happens.

Q. Now, you have included the Homeseekers D-4 sand in your overall reserve estimate, have you not? A. Yes, sir.

Q. And you have stated that that Homeseekers D-4 sand has not been tested; isn't that correct? A. That is true.

Q. Now, why did you include the Homeseekers D-4 sand if it had not been tested? A. Well, we firmly believe that if a sand closely resembles, that is, if the electric log characteristics of a certain sand that, say, has not been tested but closely resembles the electric log characteristics of a sand that has been tested in the same, say, range and depth, that the possibility is very good that that sand also has hydrocarbons present in it.

Q. In other words, you have taken the logs run in the Homeseekers D-4 sand and compared them with logs run in one of your other sands and have concluded that in all probability there is gas in there? A. That is correct, yes.

2330

Q. But from the log alone, you cannot tell whether there is gas or oil there, isn't that correct?

Mr. Deakins: That is objected to as repetitious.

Presiding Examiner: Oh, I understood the witness to say the only way you can be sure is to drop a bit into it.

The Witness: The only conclusion you can make is that in a field of this nature where the majority of the sands, except for one very small little oil reservoir present—that all the rest of the sands have been gas-bearing, and we have to draw our conclusion that this sand also if it is going to follow the same trend will be gas-bearing.

By Mr. Lewnes:

Q. But you have not taken any cores from this reservoir, any cores from the Homeseekers D-4 sand, isn't that correct? A. I do not believe; no, sir.

Q. Well, could you check that and state definitely whether you have or you have not? A. I don't——

Q. I believe you will find that on one of your work papers, which is titled "Basic Data for Reservoir Evaluation," about the fourth sheet—— A. No, there were no cores taken that we used to make any estimates.

Q. And the reserves in the Homeseekers D-4 sand have been included in Mr. Marshall's availability study?

2331

A. Yes, sir; they have.

Q. Now, will you refer to page 1 of your Exhibit X-2, specifically to lines 16 and 18, where you indicate that you expect to recover about 93 percent of the initial gas in place.

Is this a normal recovery factor for gas fields in southern Louisiana? A. In our opinion, this is the recovery that we expect from this particular field.

Q. Well, in relation to recovery factors of other fields in southern Louisiana, is this high, low, or approximately the same?

Mr. Deakins: I object to that, Mr. Examiner, because the statement is improper. It doesn't take into consideration the many different fields and different formations.

If it had the word "similar" I wouldn't have any objection. This is just all encompassing. This man is a lay witness. It may be an oil field that is on pumps now.

Mr. Lewnes: Well, let me ask the question this way, Your Honor.

By Mr. Lewnes:

Q. Mr. Olson, do you know of any field, similar field, of similar sands and similar depths, that have a recovery —that have gotten a recovery factor of 93 percent of the gas in place?

2332

A. Are you referring to something that I have made an estimate to or are you referring to something that somebody else has made an estimate to?

Q. Actual recovery. A. I do not believe we have any major fields of this size in south Louisiana that have been completely depleted to say definitely that 93 percent of the gas has been produced.

Q. Do you have any smaller fields of the same type of sands, at the same depths, that have had a recovery factor of 93 percent? Do you know of any? A. I don't know of any smaller fields particularly, no. I do know of some wells that are located in some of our good gas fields in Louisiana that will certainly approach this or have approached it already.

Q. Well, in your 16 years, I believe you stated, in your expertise of 16 years in the field of geology has it been your experience that you have recovered as high as 93 percent of the initial gas in place in any field anywhere in the United States that has similar sands at similar depths as the Rayne field? A. As I have stated, I firmly believe that the recovery that I have used on this Rayne field is a reasonable recovery, and is a recovery that can be expected in this particular case.

2333

Mr. Lewnes: Mr. Examiner, I submit that the witness has not answered the question put to him.

Presiding Examiner: Will you read the question, Mr. Reporter.

(Question read.)

Mr. Deakins: When you use the words "you have recovered," you mean that you know——

Mr. Lewnes: That you know.

Presiding Examiner: There has been, I think he meant to say.

Mr. Deakins: Yes.

The Witness: I am sorry, I didn't quite understand the question before.

I don't know of all the areas in the entire United States, and can't state. There probably has been some in some areas that I would not know about. In this particular area that we are talking about there has not been sufficient amounts of gas produced from any one field that I know of to the depletion phase of that field where I can state that this percentage of gas has come out of the field.

By Mr. Lewnes:

Q. In other words, what you are stating in effect is, is it not, that you don't know of any similar type of field in any place in the United States that has recovered 93 percent of the initial gas in place?

2334

Mr. Deakins: I object to that question——

The Witness: No.

Mr. Deakins: —because the witness has already answered—the counsel has changed the question on him. He

answered that wells had. And counsel now puts it on a whole field.

Presiding Examiner: As I understand ——

Mr. Deakins: He said none had been depleted.

Excuse me, Mr. Examiner.

Presiding Examiner: What I understood the witness to say, that the comparable field he knew about had not been sufficiently depleted as of this date, so he could tell how much the percentage of recovery would be.

Mr. Lewnes: Well, that is precisely the follow-up question.

By Mr. Lewnes:

Q. In other words, he does not know to this date of any field that has recovered as high as 93 percent of the initial gas in place. I ask if that is a correct statement. A. And I will repeat to say that in the areas that I know of; correct.

Q. Now, what methods are used to determine the porosity of gas-bearing reservoirs? A. There are a number of methods used to determine porosity. Are you referring to laboratory methods?

2335

Q. Well, I am referring to any methods that—well, we will say any methods that you have used in connection with making reserve estimates. What methods do you normally use in making reserve estimates, that is, to arrive at the porosity of the gas-bearing reservoirs? A. Well, I normally use, if available, the laboratory analyses that have been made of the various cores to determine the porosity, using all the available core data that would be furnished me on a certain reservoir I would definitely check that data, and if it appeared that it was reasonable data, and that the lab technique had been done in such a

way that would give it a reasonable porosity or give it a true porosity of what that sand had, then naturally I would use all of that available core data in arriving at my average porosity for the entire reservoir.

Q. What other methods might you use, other than core analyses? A. If I had no core analyses available I would have to make the best reasonable estimate that I would know at that time that could possibly be used as the porosity for that particular reservoir. I would use the fields in the area that had porosity taken at similar depths, that closely resembled this particular field that I did not have any information of.

Also you could use the electric log and microlog,

determining porosity, if you deemed it so advisable.

Q. Would you say that the core analyses that you have used, and as shown on the work papers supplied to the Staff, were adequately tested in the laboratories? A. Yes, I would say so.

Q. Now, here, again, if you did not have any core analyses would you revert to a quantitative analysis of electric logs? A. Not necessarily.

Q. Well, if you had no core analyses, then, would it be purely judgment? A. That is correct. I would feel that my judgment in the area would probably be more correct than using the electric log.

Q. In other words, am I correct that you do not think a quantitative analysis of electric logs for determining porosity is a proper means to determine porosity? A. I did not say it was not a proper means. It depends on the individual and depends on his experience in the area.

Q. Well, you would never use a quantitative analysis

of electric logs if you did not have core analyses? A. No, I did not say I would not actually never use one.

Q. Well, what I am trying to understand is when would

2337

you use them and when would you not use them, assuming that you do not have core analysis? A. It is difficult for me to state in a general way of specifying that in one case I would use it and in one case I wouldn't use it. There are a lot of factors that would depend on it, and I couldn't say definitely that just because I didn't have any core analyses that I would definitely use the quantitative analysis.

Q. In other words, depending on the specific situation you might feel a quantitative analysis of logs might be a good basis for determining porosity, yet under another given situation you might determine that it was not? A. That is correct.

Q. Now, how did you determine the porosity for the Rayne field reservoirs? A. They were determined by a great amount of core data that was available for this particular field.

Q. For which reservoir was the core data available that you used to determine porosity? A. Most of the cores were taken in the reservoirs that had the greatest amount of gas, an dthose were the Klumpp D, Homeseekers E, and the Nodasaria A.

Mr. Deakins: Did you say most of them were, or is that limited?

The Witness: Most of the core samples that were taken in

2338

the field were taken in the reservoirs that had the majority, that is, that represented the majority of the gas.

By Mr. Lewnes:

Q. Now, am I correct, then, that all the cores that you had, and the data relating to those cores which have been submitted to the Staff, relate solely to the Klumpp D, the Homeseekers E, and the Nodasaria E? Is that right? A. There may have been some scattered core analyses in some of the other reservoirs that I felt there weren't a sufficient number of samples taken to be representative for that particular porosity in that reservoir.

Q. Well, then, what did you use as a basis for determining the porosity for these reservoirs where you had no core analyses or you had core analyses which you thought were not adequately representative? A. Well, I attempted to correlate as closely as possible the porosities that were available in the various ranges of depths in this reservoir, and then used my judgment in the numbers of years I worked in this area and tried to use in my best judgment of the best estimate that I could come up with for that porosity in reservoirs where I did not have core data available.

Q. So for those other reservoirs it was in a sense purely judgment? A. More or less; yes, sir.

2339

Q. If you can, can you indicate why sufficient cores were not taken in the other reservoirs? A. No, I can't.

Q. And just following my previous question one step further, the judgment applied to the reservoirs which you did not have core analyses for, that judgment was based primarily on the cores from the reservoirs—rather, the cores you did have from other reservoirs in Rayne field? A. That certainly helped me in making my decision; yes, sir.

Q. Now, you have used the permeability cut-off, haven't you? A. Could you ——

Q. I will ask you —— A. Could you define for me what you mean by permeability?

Q. I was going to ask you to define it, but I preceded it with the question that you have used it and if you have used it you can define it in the manner in which you have used it. A. Yes, I generally use some approximate cut-off on permeability, as the difference between, say, a sand that would be permeable to flow gas or a sand or close—say closer to a shale that would not contain gas or have an extremely low permeability and would assume it not to be gas-

2340

bearing.

Q. Now, how does the use of this method affect your porosity results? That is, could you explain it mechanically, that is? A. Well, during the process of coring a well, they core or attempt to core the entire section or the entire productive section of the reservoir. And in so doing naturally they core some shale along with sand.

Q. Do you have your logs—— A. I haven't quite finished.

Q. Oh, I am sorry. A. So in the shale areas your permeability naturally would be very, very small, and the sand would not be productive. So, naturally, that part of the core analysis would not be used in the determination of your average porosity.

Q. Do you have your log for the Gerard Mouton No. 1? A. I do not have that log with me; no, sir.

Mr. Lewnes: Mr. Examiner, we are going to go into a rather lengthy cross-examination of this log, if you want to take a recess.

Presiding Examiner: All right, we will take the afternoon recess at this time.

(Whereupon, at 3:19 p. m., a recess was taken until 3:29 p. m. of the same day.)

Presiding Examiner: O. K., are you ready, Mr. Lewnes?

2341

Mr. Lewnes: Yes, sir.

By Mr. Lewnes:

Q. Mr. Olson, do you have your logs for the Gerard Mouton No. 1? A. No, I do not.

Q. Well, I hand you a copy of that log and ask you if this is not the log, a log similar to the log that you used? A. Yes, it is.

Q. Will you look through that log and state what the top of your net pay is, that is, what depth is at the top of your net pay? A. Would you clarify that question, or rephrase it, as to exactly what you mean by the top of my net pay?

Q. At what depth is the top of your net pay, that is the figure, the footage? A. In which particular reservoir are you talking about?

Q. The one that is down there at about 11,200, or 11,200 feet, I am sorry. A. The top of this particular sand known as the Klumpp D Reservoir I picked at 11,198 feet.

Q. All right. And at what depth is the bottom of that same reservoir, for your net pay? A. The bottom of the sand I picked at 11,253 feet.

Q. Now, what log are we using in picking the tops and

2342

bottoms of your net pay? Is that an electric log or is that a microlog? A. I am using the electric log in this case, sir.

Q. Now, how much net pay have you given for this interval? A. I picked 44 feet of net pay in this interval.

Q. So am I correct, then, in stating that within this interval you have eliminated 11 feet and have arrived at 44 feet of net pay? A. That is correct.

Q. Now, do you have the core analyses for the same well at that same particular depth, for that reservoir? A. I don't have it here.

Q. Well, I hand you a group of papers. Subject to your check, I will ask you whether these are not copies of the core analyses for some of the subject reservoirs? A. Yes, sir; this is taken from this well.

Q. Now, is it not a fact that from this core—will you strike that, from this core, and we will say: Is it not a fact that the interval you have just given has been solidly cored? A. It was cored from an interval of 11,196 to 11,245, and then some additional cores were taken from 11,255 to 261.

Q. Well ——

2343

A. There is an interval there, it appears to me, of 10 feet, that I don't see has been included.

Q. Well, now, the eight feet that have not been cored, that is, there has been no coring, that is down at the base of the sand, is that not correct? A. Ten feet.

Q. Ten feet. A. That is shown towards the base; yes, sir.

Q. So we have approximately 47 feet of coring? A. That is right; yes, sir.

Q. Now, what is the average porosity for this interval, and how did you determine it? A. All I can tell you is the average porosity I got for the sand, or for the reservoir. I used an average porosity for this particular reservoir of 21.8 percent.

Q. Well, I want to know what the average porosity was

for this interval, for this particular well. A. One moment, please.

The average porosity that I came out for this particular well was 21.6 percent.

Q. Now, how did you arrive at that porosity? A. That was arrived at by averaging the total of 22 samples.

Q. Well, in other words, you eliminated 25 samples? We are talking about core samples.

2344

A. If there happens to be 47, and I used 22, I must have eliminated 25; yes, sir.

Q. And why did you eliminate these 25 samples? A. It was done as a combination of two reasons. Judgment being one, and the fact that some of the samples indicated too low a permeability and I just considered them not representative.

Q. When you say low permeability samples, you mean they were not productive; is that correct? A. I cannot say that they are definitely not productive. It is just the judgment factor that I use where something could have happened to the sample possibly, and the permeability was not a good permeability, but also that there might be some tight streaks in this interval that indicated low permeability, and I would have considered those streaks to be non-productive.

Q. Well, isn't this a demonstration of the use of what you have referred to as your permeability cut-off? A. In some—in that respect, yes.

Q. And I believe you did testify previously that in your permeability cut-off you have cut out those—you cut out those samples which are non-productive. I believe you so testified earlier, is it not correct? A. I said that it was quite likely they would not be productive.

2345

Q. Now, when we referred to something that has a low permeability sample, we in effect are saying that we are talking about a sample that has a very low porosity, are we not? A. They sometimes coincide, yes.

Q. Do they happen to coincide in this particular case? A. Not in all cases. I see some permeabilities here of 9 and 7 Millidarcies, with porosities of 20.1 and 20.7 percent. Also there are cases where there are permeabilities of .2 Millidarcies, with, say, a porosity of 2.2.

2346

Q. Well, it is a fact, is it not, that the majority of the samples you have eliminated on this low permeability cut-off—the majority of those samples do indicate a low porosity. A. The majority do, yes, sir.

Q. If I may use the blackboard, Mr. Examiner. I shall certainly try to narrate this in such a manner that the recorder will get it.

Q. Mr. Olson, am I correct—and I draw this chart here, where this indicates a log and it shows the top of your net pay at 11,198 and the bottom of that same sand at 11,253. And you have indicated that the net pay within this sand is 44 feet, is that correct? A. Yes, sir.

Q. Now, we have stated that coring had been done between 11,196 feet and 11,245 feet, and that there had been approximately 47 samples of coring in between that distance, is that correct? A. That is correct.

Q. Now, you have eliminated, I believe you stated, or you have used only 20 of these cores within this interval, isn't that correct? A. 22?

Q. 22. A. 22, yes, sir.

2347

Q. So that in effect you have eliminated some of the cores in between here and have come up with an average porosity of I believe you said 21 point——A. Six.

Q. Six. A. Yes, sir.

Q. And that is with the use of only 22 cores. Yet, is it not a fact that you used this porosity and applied it to the entire 44 foot net pay? A. I used that porosity for that particular well, yes.

Q. And you applied it to the entire 44 foot of net pay? A. You can't exactly say that I applied it to the entire 44. I used it as one porosity for one well in that particular reservoir.

Q. Well——A. In this particular case I found that the representative porosity that was taken on this particular well was 21.6.

Q. In other words, for this particular well, you said you used a net pay of 44 feet and a porosity of 21.6. A. That is correct.

Q. All right.

Now, since you did eliminate some of the core samples with low permeability which were nonproductive, is it not a fact that you should then have applied this 21.6 percent

2348

porosity to a net pay reflecting that same elimination of these core samples? In other words, you would use the 21.6 percent porosity and relate it purely to approximately 26 feet of net pay, if you were consistent in the use of your cores as you applied it to the net pay shown on your logs. A. No, you can't look at it entirely that way. Simply because I never saw the cores or any of the cores myself, with my own eyes, that were taken out of this well. There could have been some cores that were taken out of this

well that were contaminated with drilling mud and what-not and also some cores that when they got to the laboratory were in such a fashion that they did not produce a representative sample on the laboratory analysis.

Q. Well, you previously testified that all the cores as indicated on your work papers were good core samples and that they were reliable, in essence I believe you so testified? A. In the majority of cases, yes.

Mr. Deakins: That is not what he said in reference to this, Mr. Examiner.

Mr. Lewnes: I believe the witness has indicated that he stated in effect the same as I have put it to him.

By Mr. Lewnes:

Q. Now, is it not a fact that if you used all the cores as they related to this exact 44 feet of net pay which

2349

you have used, that you would have come up with a porosity of 17.3 percent? A. Could I ask you now how you arrived at this 17.3 percent? You added up all the cores, is that my understanding?

Q. That is correct, all of the cores as they would relate to the 44 feet net pay that you have used, and averaged them out in the same manner that you averaged them out, without the elimination of the cores in between. A. Not taking out any, but just averaging them all.

Q. Right. A. If that is the figure you came out with, I assume that that figure, or your percent would be correct there. However, that is not the way I did it, and that is just a way of whether one person would do one thing and another person would do another thing. But I don't do it in that particular manner.

Q. Mr. Olson, if you eliminate the core samples that show a low permeability which by your own definition are

non-productive, why is it that you included—you nevertheless included it in your net pay, that is include that same strata in your net pay? A. Well, as I said before, I don't know what the conditions of all these cores were.

You can't take a particular point here and say that all

2350

of those cores came out in the same condition, that one core came out the same way as another core did. The only thing you can do is to say that the majority were representative, and you have to use, in your best judgment, what you consider to be the ones that represent the porosity to be the best.

Q. Well, in other words, you are saying in effect that some of the cores are good and some of the cores aren't good, and in your judgment you picked out the ones that weren't good. A. In my judgment the way the laboratory has come out with their analyses, that I feel that some of them definitely have to be thrown out, whether it is due to the fact that the core was broken up too badly or contaminated or something like that or actually due to the fact that in that particular reservoir there was a shale bed that had a low porosity.

Q. Well, but these cores for this particular reservoir. Can you state that you know exactly what the laboratory conditions were under which the results have been set forth in your work papers? Could you state from those work papers whether these cores were good or were not good as far as laboratory testing was concerned? A. No, I can't, because I said I did not see the cores.

Q. In other words, how do you know which to eliminate

2351

and which not to eliminate depending on whether good laboratory analysis was conducted or not when you don't

know what analysis was that was conducted on these cores? A. Well, I attempted to tell you that I used this permeability barrier, I mean cut-off point for one reason of cutting out certain samples.

Q. Yes, sir——A. Now, I have to base my conclusions on something.

Petroleum engineering is not a definite science, in that you have to use a lot of judgment in how you use material. You can't point your finger at one point and say just because this is this way that is the way it is going to be, because it isn't.

Q. Well, how did you determine porosity for the Klumpp D reservoir? A. I had core analyses from three different wells in the Klumpp D reservoir, one of which was this Mouton No. 1, one was the Dupuis No. 1, and the other was W. Petitjean No. 2.

From these three wells I used a total number of samples, of 55 samples—a combination of all three wells—and weighted those out and arrived at my porosity that I used in this particular exhibit.

Q. So you used core samples for the determination of your porosity for the Klumpp D reservoir.

2352

A. Yes.

Q. Is that correct? A. Yes.

Q. Can we logically conclude that in all the other reservoirs as to which you made a determination of your porosity on the basis of core samples, that you used the same type of permeability cut-off? A. Generally speaking, yes, sir.

Q. Now, if you decrease net pay, all other factors remaining constant, does it not follow that you decrease the overall reserves? In other words, given a given situation with a set of given facts and a specified figure of reserves. Now, if you take those facts and leave every-

thing constant but decrease the net pay, you ultimately would then arrive at a lesser reserve figure, is that not correct? A. That is correct, yes, sir.

Q. And, again, all factors remaining constant, if you decrease porosity similarly, you get a lower reserve estimate? A. That is right, yes, sir.

Q. I refer you again to your Exhibit X-2, page 1, with specific reference to line 7 under the Klumpp E sand.

Now, your present porosity there is reflected as 24.9 percent. Yet in your 1957 reserve estimate which was submitted in these proceedings, it was 21.0 percent. Is that not

2353

correct? A. I do not have that exhibit here. Could I ——

Mr. Deakins: We don't have it here.

Mr. Lewnes: We have a copy of it.

Presiding Examiner: Is that Exhibit M-13?

Mr. Lewnes: Well, Your Honor, this is an exhibit from the formal filings. I don't think it is the exact exhibit that was—this is not the exact exhibit, I don't think it is the—oh, excuse me.

No, Your Honor, this is part of Exhibit X-4, which was submitted in the proceedings originally, and actually it is the exhibit that was contained in the application itself, I believe. And it is marked Texas Eastern Transmission Corporation, estimated reserves and availability of natural gas in the Rayne field. Acadia Parish, Louisiana, as of January 1, 1957, filed with this Commission April 22, 1957.

Presiding Examiner: I see, M-13 was filed in connection with the 1959 estimate.

Mr. Lewnes: That is correct, Your Honor.

The Witness: Yes, I see that.

(2353)

By Mr. Lewnes:

Q. Was I correct that you there reflect a porosity of 21.0 percent for the same Klumpp E sand, whereas you now reflect a 24.9 percent porosity? A. That is correct.

2354

Q. Now, could you state the reason for this change in porosity figures? A. I am not exactly sure how I arrived at this back in 1957. My memory kind of—it is a little bit vague about that time.

But I would say that one reason for using a larger porosity in this particular—in this exhibit, other than the 1957, was or could be due to several reasons. One being that we now had many more wells in the field. We had more electric logs to look at. We also had more core information available on the other reservoirs. And as a result, we decided that that porosity should be larger at this time than it was during the time that we had a lot less information.

Q. Well, isn't it a fact that you do not have any core analyses for the Klumpp E reservoir? A. That is correct.

Q. So are you saying—— A. Now, it is possible that we had some two or three or four samples taken in that particular reservoir, and if I remember correctly those samples showed from 26 to 27 percent porosity, which I deemed was too high in this particular case and did not use those samples.

Q. Did you state that you made some electric log calculations in regards to arriving at this present day porosity for the Klumpp E?

2355

A. No, I did not state that. I just stated that we had more electric logs—more wells drilled and more electric logs run, than just checking the characteristics of the sand on the electric log.

Q. Well, you are talking about more logs run. What data were you referring to now? Were you reffering to logs run recently, in 1960? A. Well, more wells drilled than since the report of this data in 1957. I believe there were only 8—let's see. Thirteen wells I show on this particular exhibit.

Q. Well, Mr. Olson, when did you make this reevaluation of all the information to date and then make the change of 24.9 porosity figure for the Klumpp E sand? A. We have kept abreast of these reserves ever since the first time we ever made the reserve estimate, and have brought up our estimates periodically, that is checked our estimates and brought the field up to date, or to whatever date we were working on at that time.

But we keep up with our structure and isopach maps and all other pertinent data that would keep coming in and swelling our file on information on the field.

In my 1959 report I also, I see, used the same porosity. So I assume it was back at least that far that we changed this porosit yin this particular reservoir.

Q. Is it not a fact that on your basic data sheet

2356

contained in your work papers for this particular reservoir you have, or there is an indication "insufficient core data based on judgment"? A. That is right, yes, sir.

Q. Did you use irreducible water samples to determine your interstitial water? A. In some reservoirs, yes, sir.

Q. Could you specify which reservoirs and which wells? A. The reservoirs that I used this data on was out of the Klumpp D, the Homeseekers E, and the Nodasaria A.

Now, the wells were the Nodasaria A sand. Information pertaining to irreducible water or capillary pressure data, so to speak, was on the E. A. Arceneaux No. 1 well, the Dupuis No. 1, the Dugas No. 1, also known as the

Nodasaria Unit No. 7, the T. Petitjean No. 1 and the W. Petitjean No. 2.

On the Homeseekers E sand, the wells that had this data were the Mouton No. 1, Arceneaux Senior No. 1, and the W. Petitjean No. 3.

And on the Klumpp D reservoir, the wells in that particular reservoir were the W. Petitjean No. 2, the Dupuis No. 1, and Mouton No. 1.

Q. Mr. Olson, would you explain the terminology or the differences in the meaning of connate water, interstitial water, and irreducible water?

2357

A. Connate water and interstitial water are one of the same, and irreducible water is the water in the sand grains above the transition zone of the reservoir.

Q. Well, by your meaning of the transition zone—in other words, if I were to understand this properly, you would have an irreducible water on the top, followed by a transition zone beneath it, and then we arrive at the gas water contact or the water saturation, is that correct?

A. No, that is not correct.

I could draw this on the board, but I guess——

Q. Well, it is all right with me.

Presiding Examiner: If your explain it as you go along, so we will get it on the record.

The Witness: Good.

These two lines here represent the well bore and this line here represents, say, our long normal curve line on the resistivity side.

Let us say this being the self-potential side of the log, that the total sand thickness is from here to here (indicating).

The area shown here, down to the break-off point here (indicating) would be what we would consider the area

containing the hydrocarbons, in the particular reservoir, whether it be oil or gas.

This line coming in here indicates that it is changing from hydrocarbons to water, being that we still have ample amount of sand here on this side.

2358

We would say that a point approximately here would be 100 percent water line, or from this point on down would be 100 percent water in the sand (indicating).

The line drawn across at this particular point or the inflection point of this curve coming back into the shale line, would be the approximate point of either the oil water or gas water contact of the particular sand.

The area contained in here from that line down to the 100 percent water line would be what we would call the transition zone of the sand or the part of the sand that would contain part oil and part water.

The oil percent would be a little greater up in here, and then the water percent would get greater as you approach the 100 percent water line.

Then this particular area right here would be the area that we would consider the production of this particular, whatever it be, oil or gas, to come out of this particular reservoir.

And this would be the area where we would term the irreducible water would be found.

By Mr. Lewnes:

Q. Mr. Olson, is it not a fact what you have shown here is a rather thin transition zone and that all cases do not show such a sharp decline of the transition zone as you have indicated, isn't that correct?

2359

A. I have shown a small transition zone here, yes, because

it represents the type of transition zone we would find in this particular field.

Q. Are you stating that your logs that you have used in this proceeding do not show a more gradual approach through the transition zone down to the gas water contact? A. This is my gas water contact (indicating).

Q. Pardon me? A. This is my gas water contact here. Are you referring to the 100 percent water line?

Q. Yes, I am. A. These sands in the larger reservoirs that we have in this field, namely the Klumpp D, the Homeseekers E, and the Nodasaria A, are very thick sands. And I believe that I could state that the transition zone on all of those reservoirs would be very small.

Q. So, in other words, again, if I am correct, you are stating that none of your logs for any of these wells show a transition zone in a more gradual form, that is going from what you have called your gas water contact, through, up to your 100 percent water saturation—none of your logs show a more gradual approach than that which you have indicated? A. Well, now, I can't say exactly what I have indicated here would be found on every log.

2360

I have given you an example here. And I have stated that the transition zone on these three major reservoirs that I have defined are comparatively small when you correlate them with the entire thickness of the reservoir, yes.

Q. All right.

Now, how have you determined your interstitial water, in these proceedings? A. Well, I have used this capillary pressure data where it was available on these three reservoirs that I have already indicated, and I have used these or the data or curve that was constructed, using the basic data in order to construct the curve permeability versus

irreducible water I used this curve in each case of each well, using all the permeabilities that I considered representative and averaged, taking off the permeabilities off the core analyses and applying that to the curve that went along with this data, and then obtaining off this curve the various percentages of irreducible water and averaging all these particular samples up in each one of these wells to arrive at the average interstitial water for the reservoir.

Q. Well, when you talk about these curves, are you talking about the irreducible water graphs? A. That is right. It is—well, the title of the curve is called irreducible water versus permeability.

2361

Q. In other words, here again have you not applied your permeability cut-off, that is you only used those samples that you thought were representative of permeability, again eliminating some of them? A. I used the samples that I considered to be representative, yes, sir.

Q. Is it not a fact that the low permeability samples that you have eliminated do in fact have a higher connate water than the permeability samples which you have used as representative? A. That is right, yes, sir.

Q. Now, in your direct testimony I believe you stated that you had made electric log calculations in arriving at your connate water? A. In some of my other reservoirs where I did not have this particular data of capillary pressure data, I certainly looked at the electric log, to use that as one factor in making my decision on what to use for an estimated interstitial water on other reservoirs where I did not have the capillary pressure data.

2362

Q. Well, you just stated you looked at electric logs. I am referring to your statement that you made electric

log calculations. When did you make these electric log calculations? A. I made them during the course of my particular work, in making up this estimate.

Q. You mean in making up this present estimate here, and not the 1959 estimate? A. Well, I always use the same methods, no matter what year I make an estimate.

Q. When were the irreducible water graphs made available to you? A. I am not positive when we received this data. But I believe we had this data—I know we had this data—I know we had this data for 1959 estimate and I am not positive whether it was available during 1957.

Q. Is it not a fact that the Staff requested that you supply it with the electric logs calculations you referred to? A. The electric log calculations that I made I didn't even bother to keep myself.

Q. Well, it is a fact, is it not, that the Staff did request the electric log calculations? A. It is possible that they did, yes.

Q. Well, did they request them or did they not request

2363

them? A. I believe they did request them, and I had stated at the time they requested them that I just had made hasty calculations on a piece of paper and didn't even have them, myself. Q. In other words, you have all the work papers or the work data that you used to determine the reserves in these reservoirs, exclusively of the electric log calculations which you said you made? A. No, I probably made many notes about many things that I never kept in making up my calculations. I don't keep every scrap of paper that I use.

Q. Well, am I to infer from what you have just stated that you normally make these electric log calculations in any estimate you might prepare? A. I use all the avail-

able data that is available to me. If the electric log is available to me, I will use that.

Now, I may find in my calculations of an interstitial water calculation off of an electric log that in my own best judgment is not a representative interstitial water calculation or is not a representative interstitial water percent, because of my knowledge of the area. Or it may be something happening in the running of the electric log that would not exactly give me the proper percentage or the range in percentage that

2364

would normally be found in this particular area.

So I might run an electric log calculation on interstitial water and find it not to be representative and just discard it and say I can't use that.

I might add that a lot of things we use are tools. They are not perfect science tools. And we have to use an awful lot of judgment in whether some basic information is good, or whether it isn't good.

So to arrive at, say, one interstitial water percentage does not mean that I have arrived at it by just using one factor. I have arrived at it by probably several factors involved in it.

Q. It is a fact, is it not, that the connate water that you have used in your exhibits in 1957, 1959, and the present exhibit have not changed, I believe, except for one very minor alteration; is that correct? A. I would—if you have checked it, I will accept that as correct.

Q. Now, your testimony in regards to the 1959 exhibit, which appears at transcript page 1346, indicates that you used coring. And no mention is made of having made any electric log calculation at that time, or the use of irreducible water graphs?

Now, can we safely assume that you did not have the irreducible water graphs when you made your 1959 exhibits, and

2365

that you did not make any electric log calculations when you prepared your 1959 exhibits? A. No, you cannot assume that, because that wasn't stated at that time. It was just left out for some unknown reason.

Q. Now, what tests are run on the cores in the laboratories—and keep it consistent if you like—in order to arrive at the factors used in the irreducible water graphs? A. Would you rephrase that or just make it a little more explicit as to what you are driving at?

Q. Well, for example, in order to arrive at irreducible water graphs, where are irreducible water samples taken from? A. Well, the samples, of course, are taken through the entire reservoir, or how many. It may vary from one sand to another, how many samples they take.

Q. Well, do you take them in the irreducible water zone, or do you take them in the irreducible water zone and in the transition zone, or do you take any of them down into the 100 percent water saturation zone? A. It is possible that cores could be taken all the way from the top all the way down to here.

Q. Well, which ones do you use in making up your irreducible water graphs? A. The samples that are used are from this point to this point.

2366

Mr. Deakins: Why don't you state what those points are?

The Witness: From the top of the pay down—well, I take that back. I am not positive exactly what cores—well, yes, I know what cores they used, because they state in there according to depths. They could take samples

all the way from the top of the pay, say, down to or including the 100 percent water line.

By Mr. Lewnes:

Q. But in order to arrive at your interstitial water, is it not a fact that you would not use any irreducible water samples taken in the transition zone? A. Let me state that we are not interested in the transition zone, to begin with, because we have not used any net pay in that particular zone.

Q. In other words, in every one of your net pay determinations you have taken the bottom of your sand at some point above the transition zone; is that correct? A. We have counted the net pay from the top of the sand down to the gas-water contact. The gas-water contact, the way we pick it normally, is right at the top fringe of where the transition zone starts. Now, if we were to pick this point of 100 percent water as our contact point, then we would have had to include the net pay within the transition zone. We did not do that in this case because of picking our gas-water contact right at the top fringe of the transition

2367

zone. So this is the only area that we are interested in, and the only area that is represented in our reserve estimates.

Q. One final question, again. So, in other words, in order to arrive at your interstitial water in relation to the way you have picked your net pay, you would not use any irreducible water samples taken in the transition zone; is that correct? A. That is correct.

Q. And you have not? A. No, sir.

Mr. Lewnes: I think we can quit at any convenient time you like.

Presiding Examiner: The court will be in recess until

10 o'clock tomorrow morning, at which time we would reconvene in the Indian Claims Commission hearing room No. 4808.

Off the record here.

(Whereupon, at 4:30 p. m., the hearing was adjourned until Wednesday, December 6, 1961, at 10 a. m.)

2368

Wednesday, December 6, 1961.

* * * * * * * *

2369

PROCEEDINGS

Presiding Examiner: Are there any preliminary matters this morning?

E. A. Olson

resumed the witness stand and, having been previously duly sworn, was examined and testified further as follows:

The Witness: Mr. Examiner.

Presiding Examiner: Mr. Olson.

The Witness: After having the opportunity of reading over the transcript of yesterday afternoon, I found a few instances where I believe there were some misconceptions on how I used the material that was available to me in arriving at some of my estimates, and I would like to clear up the record, if I may, at this time in making it more clear in the record of how certain things were arrived at.

Presiding Examiner: You may proceed, Mr. Olson.

The Witness: In the first instance, I would like to turn to page 2331 of the transcript.

Presiding Examiner: Mr. Olson, you mean 2231.

The Witness: Excuse me. I have page number 2331.

Mr. Deakins: Volume 19, Mr. Examiner.

The Witness: Volume 19.

Mr. Deakins: Do you have that?

Presiding Examiner: Oh, I am sorry, I was looking at the wrong one.

2370

The Witness: And on line 2, Mr. Lewnes referred to a recovery of 93 percent that I had used in my exhibit.

I wish to first state that no place on my exhibit X-2 on page 1, do I use or do I have 93 percent shown.

I wish to also state that I have used here——

Presiding Examiner: Mr. Olson, in that connection, as I recall what staff counsel asked you was this. In Exhibit No. 2, X-2, at line 16, you estimated the gas in place to be so much.

The Witness: Yes, sir.

Presiding Examiner: Over in the total column marked "M". And then on line 18 in that same column in this same exhibit you estimated the recoverable gas at so much. And as I recall, he said to you—if you take his figures, which was roughly 93 percent.

The Witness: That is right, except I would like to clear the record on recovery of the particular reservoirs—I would like to bring out the abandonment pressure in order to prove some points about the recoveries that we expect in this field.

Presiding Examiner: Go right ahead, sir.

The Witness: We have used in this case 500 pounds which we certainly feel is reasonable abandonment pressure to use. And we also feel that the wells are certainly capable and feasible to arrive at this poundage for abandonment

2371

pressure.

Now, we base this on several examples that we have in this particular area, namely in the Iowa field in Calcasieu

Parish, in which case—this field is a field that is faulted up considerably. However, there are wells that are in separate fault blocks and you could consider them as an individual reservoir producing out of a single fault block.

We have examples here, Mr. Examiner, of wells that were abnormally pressured at about 9,000 pounds at a depth of approximately 10,200 feet, at which time they are now producing, are still producing at pressures below 500 pounds.

We also know of areas in the country other than South Louisiana where there are many cases where wells are producing below 500 pounds.

I do not have those areas in mind at the moment, but if staff counsel wishes we can furnish him with a copy of those particular fields and areas where this pressure of lower than 500 pounds can be exhibited.

Also, in the same Iowa field, which is more pertinent in this particular case since it also is an abnormally pressured field, there are several wells that are still producing 200 and 300 Mcf per day, at flowing tubing pressures ranging from 30 to 50 pounds.

So with this added information on our abandonment pressure of 500 pounds, we feel certainly that it is reasonable.

2372

There are no entire fields in South Louisiana where the entire field has been depleted below pressure 500 pounds.

The reason for that is because particularly in the abnormally pressured fields these fields only came into existence a few years ago and they have not had the opportunity to produce a sufficient amount of gas to deplete the reservoirs.

Mr. Lewnes: Mr. Examiner, I don't intend to interrupt the witness, but perhaps it would be better if on each

phase of this addition to the testimony we could cross-examine on that particular phase, rather than repeat ourselves by going back to what he previously said.

So if this is going to cover—if this is all the additional testimony on the recovery factor, I think it might be most proper if we cross-examine him on that particular phase right now.

Presiding Examiner: Did that complete your statement on that point?

The Witness: On that particular phase.

Mr. Deakins: I think that is the right way to do it, too.

Presiding Examiner: Then, Mr. Lewnes, if you have some questions to ask on this particular phase of his testimony, you proceed with it.

2373

CROSS-EXAMINATION (Cont'd)

By MR. LEWNES:

Q. Am I correct now, Mr. Olson, that you have stated that you know of the specific fields that have been depleted down to 500 pounds abandonment pressure? A. I said not in the south Louisiana area, but there are undoubtedly some fields in other areas of the country that I don't have the information available at this time on, but that I am confident that they are producing well below the 500 pound abandonment pressure.

Q. In other words, what you are saying is that you are using south Louisiana wells to prove up the abandonment pressures which you indicate for Rayne field, but you do not have any comparable fields to Rayne field that you could make that comparison with, in south Louisiana? A. The reason I brought out the other areas, Mr. Lewnes, was that you asked me yesterday, do you know of any fields throughout the entire United States where this

exists or where you can obtain 93 percent recovery. And we can exhibit some cases in other parts of the country, yes, sir.

Mr. Lewnes: Will the Examiner request the recorder to read back my question to the witness.

Presiding Examiner: Yes. Will you read the question, Mr. Reporter.

(Question read.)

2374

The Witness: Yes, the field that I named, of Iowa field, is a comparable field in many respects to the Rayne field. That is why I used it as an example.

By Mr. Lewnes:

Q. But that field has not been depleted down to 500 pounds abandonment pressure? A. There are several wells in separate fault blocks that I stated could be assumed as being one reservoir that are producing below 500 pounds.

Q. So, again, we are talking about wells and not fields? A. We are talking about individual reservoirs that could be actually considered a field by itself.

Q. You have stated that these wells which you are referring to, the Iowa, in the Iowa field, have numerous separate faults. Are you stating that those, that is the fault patterns existing there are identical or similar or as numerous or—all right, as the fault patterns in the Rayne field? A. The fault picture of Iowa field is not exactly the same as the Rayne field. No field is exactly the same in faulting. However, I don't see any bearing on what that has as far as the capabilities of the wells to produce below the 500 pounds.

Mr. Deakins: Did you mean not the same in faulting—

2375

you mean not the same as any other field, or as——

The Witness: Well——

Mr. Deakins: You left your answer in the air there, as far as I am concerned.

The Witness: I meant to say that the faults found in Rayne field may run in a little different direction than, say, the faults that run in the Iowa field. They wouldn't be, say, exactly the same size. They would be comparably the same size. But you don't find the exact picture on a structure map of one field that you would find on another field.

Mr. Deakins: O. K.

By Mr. Lewnes:

Q. Mr. Olson, isn't it a fact that if a well is in an individual fault block, that fault pattern has a direct bearing on the productivity of that well? A. Excuse me a second.

Mr. Lewnes: Mr. Examiner, will the record reflect that Mr. Olson has left the stand and is consulting with Mr. Marshall.

The Witness: Pardon me. I meant to ask you—did you——

Presiding Examiner: He asked to be excused.

Mr. Lewnes: Yes, sir. I just wanted the record to reflect that.

2376

Mr. Deakins: Mr. Reporter, will you read that question back? It is obvious to me from the questions this witness is discussing with me and with Mr. Marshall—I don't think he understood the question. Please read it back to him, and also for my edification.

Presiding Examiner: Read the question, Mr. Reporter.

(Question read.)

Mr. Deakins: Now, I am going to object to the question as not specific.

We have used the words "availability" and—let's see

—and "reserves" in here. But this word "productivity" is what through the witness here.

Do you mean—what do you mean by productivity? That is what I mean.

Mr. Lewnes: You can substitute the word "availability" for "productivity".

Mr. Deakins: O. K.

Well, he isn't testifying as to availability, Mr. Examiner. But——

Presiding Examiner: This line of questions goes to the amount of recovery. What he was testifying to is additional testimony this morning, which was as to the 93 percent recovery and that is what this line of questions is intended to elicit, as I understand it.

Mr. Deakins: I wanted to be certain on that. That is

right.

The Witness: I can attempt to explain it in this way. The examples that I used in the Iowa field are smaller reservoirs than we have present in the Rayne field. And we are able to see at a much earlier date the fact that these wells are capable and are still producing at 500 pounds or less and will come out with a high recovery.

Mr. Deakins: Now, that wasn't responsive to his question. Read the question back to him. Now, you answer the question he asked you, whether the fault blocks—you got me fouled up with productivity. Read that original question back to him. That is what he wants to know.

Mr. Lewnes: Well, may we have the answer that the witness just gave read, first, and then read the question back.

(Answer and question read.)

The Witness: I wouldn't say that it has any direct bearing as to the capabilities of the well to produce.

We definitely get a more instantaneous productivity index

as a result of it being in a smaller reservoir. And we can determine the recovery at a much earlier date than we can in a larger reservoir.

By Mr. Lewnes:

Q. Mr. Olson, isn't it a fact that in the Rayne field there are reservoir pressure differences on either side of

2378

the fault that you have indicated in your exhibits? A. Would you explain more clearly on which fault you are talking about and which reservoir you are talking about?

Q. Well, you can go down the line and pick out any reservoir you like or all of them. Let's go through all of them. A. We used the same pressure on all of the reservoirs, with the exception of one, the Nodasaria A, in which there is a slight difference of—in the Nodasaria A north segment we used 11,008 pounds, and in the south segment we used 10,972, which is just a very minor amount difference in pressure.

Q. Well, wouldn't the productive characteristics of the well depend to some extent on the reservoir pressures? A. I would say yes.

Q. Mr. Olson, apparently yesterday you didn't have these facts before you, and now this morning you do.

Could you tell us what the source of this information was that you are now testifying to, this morning? What was your source of that information? A. Would you clarify your question on exactly——

Q. In regard—— A. In demonstrating to me what you mean by source of information.

2379

Q. Now——

Mr. Deakins: Wait a minute. You listen to the question. The question apparently you didn't have it before you yesterday. Is that a fact or not?

(2379)

The Witness: I had this information well in hand yesterday, yes, sir.

By Mr. Lewnes:

Q. You did not testify to that yesterday. A. There are various reasons for not being able to answer some of your questions in the manner in which I would like to bring out additional information. And I am doing this this morning because I did not have the opportunity to do it yesterday.

Q. Are you stating that you were precluded from testifying in any manner you so desired yesterday upon cross-examination?

Mr. Deakins: I don't think he intends to do that, Mr. Lewnes. The reason is the witness answered the questions so precisely yesterday that he didn't give an explanation. That is what he means to say. Isn't that right, Mr. Olson?

The Witness: That is correct.

By Mr. Lewnes:

Q. In other words, what you are testifying now is that you had all this information with you yesterday, but you are now testifying as to that information today?

2380

A. Yes, because I felt that I could clear up the record in much better fashion by putting this information into the record than it was previously.

Q. All right.

Now, what was the source of the information that you have there? Where did you obtain that information from? A. I obtained it mainly from our own files.

Q. All right——

Mr. Deakins: Mr. Lewnes, if you want me to back up something.

Mr. Lewnes: Yes, sir.

Mr. Deakins: Do you have something on the Iowa field in your possession there?

The Witness: Yes.

Mr. Deakins: Well, show it to Mr. Lewnes and——

Mr. Lewnes: That is all right. I don't want to see it. He can proceed with his next clarification of his cross-examination yesterday.

The Witness: The next phase which I felt needed to be clarified somewhat started on page 2346, with regard to the porosity that I obtained in the Mouton No. 1 well, and the procedure that was used in determining this porosity.

I wish to add to this testimony the fact that was brought out yesterday, that 10 feet on the lower part of

2381

this sand was not cored. And I feel that if this 10 feet had been cored, it is entirely possible that instead of having 22 samples in this particular sand we could very well have had 32 samples, where we picked a total net pay of 44 feet.

Now, the fact that I want to bring out here, and it did not come out in the testimony yesterday, is that it is our purpose at all times to use all of the available information that we have on each reservoir.

In this particular case there were two additional wells that were cored.

And checking into one of the wells, namely the W. Petitjean No. 2, that is checking into the core analysis there, if we had taken—and this has reference to this 10 feet that was not cored at the bottom of the sand in the Mouton No. 1 —if we had taken from the gas water contact up 10 feet on the W. Petitjean No. 2 well, we would have used 8 samples out of the 10 that were cored in that well and would have come out with a percent of 21.6 percent.

I further want to state that in this particular well the top 25 feet was not cored.

Now, it is entirely possible that if the top 25 feet had been cored in this well we probably would have had around 40 some odd samples to estimate the porosity. And in this particular well I believe we picked some 40 some feet of net

2382

pay.

Which all comes around to the fact that we attempted in every case to not just use an isolated case, but to use all of the information that we had in arriving at what we thought was certainly a reasonable and correct porosity for the reservoir.

By Mr. Lewnes:

Q. Now, Mr. Olson, we aren't so concerned as to what you might have done or would have been. We are more concerned with what you actually have done.

Now, for example, you just stated that if you had the other cores taken in the other 10 feet you would have used them.

Are we to assume that you would have used all 10 cores taken in that 10 foot interval or you would have only used those that did not have a low permeability? A. I would have used what I would consider to be the best information available at that time the well was cored.

In other words, as I have stated previously, in my best judgment of what I consider are the porosities that should be used and are in the core section of the sand, that those are the ones I would have used.

Q. Now, the fact nevertheless still remains on this Gerard Mouton No. 1 well, in arriving at your porosity you took—there were approximately 47 samples, core samples

2383

taken. Am I correct? When we talk about 47 core samples we are talking about a core sample taken at each one foot

interval? Is that correct? A. Do you have the core analysis there? That would indicate whether it was taken every one foot or every half foot.

Q. I will let the record reflect that I am handing the witness the core descriptions. A. In this particular case it appears that it was taken at one foot intervals.

Q. All right.

Now—and the fact still remains that out of that 47 foot interval, where there were 47 cores, you used 22 samples, isn't that correct? A. That is correct.

Q. All right. And these 21 samples were not continuous samples? In other words, you may have taken one sample at the bottom of this 47 foot interval, a couple more somewhere in between, and a couple more on top, to fully constitute the 22. But they were not 22 continuous samples, were they? A. No, that is correct.

Q. All right. And after taking these 22 samples you in effect compacted them together, or added them up, and came out with an average porosity, isn't that correct?

2384

A. That is correct.

Q. And you took that porosity which you got from these 22 samples, which were not continuous samples, and applied it to a full 44 foot of net pay, isn't that correct? A. Yes. But you are forgetting that there are some shale breaks in this sand, Mr. Lewnes, that you wouldn't normally use the porosity of a shale break.

Q. But isn't—well, then, isn't it a fact then that you should have eliminated those shale breaks from your 44 foot of net pay, since you eliminated them in your determination of your porosity? A. I believe the overall thickness was 55 feet in this particular well, of which we used 44 feet of net pay.

Q. That is correct. And it was in that 44 feet of net pay —if you take that same 44 foot net pay interval and com-

pare it to the cores taken within that same interval, you have eliminated approximately 22 samples—25 samples from within that 44 foot interval.

Now, in eliminating those 25 samples, you did not make a similar elimination of that footage within your net pay, isn't that correct? A. Again I would like to state as I brought out yesterday, Mr. Lewnes, that the technique which is used by the oil industry has some fallacy in that everything can't be done to the exact science of engineering. And it is entirely

2385

possible that this could be an isolated case where this condition exists as you have stated. But that is where judgment comes in and that is where knowledge of the area comes in, in making your estimate.

Q. Now, irrespective of whether it may or may not be an isolated case, I believe my question went to the point of whether what I had stated was or was not a fact. Now, I ask you if you can answer that question. A. What I did and what you have stated that I have done is a fact.

Q. All right. A. And that is why I did it, because of my judgment factor.

Q. All right. Thank you.

You want to proceed?

Mr. Deakins: Go ahead now.

(Discussion off the record.)

The Witness: I would like now to clear up one last point found on page 2357 of the transcript, in which we had a discussion on the transition zone of a resorvoir, having to do with the interstitial or irreducible water.

Checking into my records, I further wanted to make sure that what I had used previously and what information I had previously was correct, and that is that to our knowledge there were no analyses made of the water percentages in the

2386

transition zone in this particular field.

If there had been any, we had no knowledge of it.

And also I would like to state that we did not include in our reserve estimate the net pay in this particular zone. If we had included it and had additional information on the water saturations in this zone, it would be my guess that our reserves probably would reflect about five percent higher than we now show.

By Mr. Lewnes:

Q. Does this conclude your clarification? A. Yes, sir.

Presiding Examiner: Mr. Lewnes, have you any questions on this last clarifying statement of the witness?

Mr. Lewnes: No, Your Honor, because our cross-examination will cover certain phases of that now.

Mr. Deakins: Are you going to——

Mr. Lewnes: Proceed with the cross-examination.

Mr. Deakins: O.K.

2387

By Mr. Lewnes:

Q. Mr. Olson, will you state in your opinion or name in your opinion some of the recognized authorities on the interpretation of electrical logs, that is, one or two firms and some of the recognized outstanding individuals who are noted for their background in the interpretation of electrical logs? A. Well, I am not sure of the names.

I can state the Schlumberger Corporation and Lane Wells—those are two of the well logging services that have competent men that are considered experts at interpreting logs. I can't name their names off at the moment.

Q. Well, did you include, then, within that definition of competent people who work for Schlumberger Mr. Doll? A. Yes, I believe I do remember an article he wrote.

(2387)

Q. And Mr. Tixier? A. That is right, yes, sir.

Q. Mr. Olson, do you have your electric log for the W. Petitjean and No. 2 in the Klumpp D. Sand which I believe you had just testified to? A. No, sir, I do not have it.

Q. Let the record reflect that I am handing a copy of that log to the witness.

Will you give us the top of the sand which you

2388

have used for the Klumpp D. as indicated by that log? A. The Klumpp D?

Q. That is correct. A. Yes, sir. The top that I picked for this particular reservoir, the Klumpp D. and the W. Petitjean and No. 2, was 11,280 feet.

Q. Now, did you pick that off your SP, or if not how did you pick it?

Mr. Deakins: What is an SP?

Mr. Lewnes: Spontaneous potential.

The Witness: You could possibly use that as a place to pick it, yes, sir.

By Mr. Lewnes:

Q. Well, is that what you used? A. I used combination of that and the resistivity curve.

Q. All right. Now where is the bottom of your sand? A. The bottom of the sand that I picked was at 11,324.

Q. And did you pick that in the same manner that you picked the top? A. That is correct.

Q. And what is the net pay? A. The net pay that I arrived at here is 42 feet.

2389

Q. Now, by looking at that log, isn't it a fact that the 16 inch and the 64 inch curves decrease steadily in resistivity from 11,275 feet to 11,324 feet? A. There is some decreasing in resistivity, yes.

Q. Well, is there a steady decrease in resistivity? A. There appears to be a uniform decrease.

Q. And does this not indicate that there is a transition zone there? A. I wouldn't say so, no, sir.

Q. Well, what would you say that that indicates? A. Well, you can get all types of variations on a log. It just probably indicates that there is a little less resistivity in that particular area, and also it appears that there is some shale interference there that would also cause the resistivity to decrease.

Q. Well, doesn't your SP curve indicate that there is sand throughout that interval? A. It indicates both sand and shale.

Q. Well, didn't you count net pay in that interval? A. Yes, sir, I did.

Q. Well, if there was shale why didn't you exclude the shale from your net pay? A. I did.

Q. Well, let me ask you a point blank question. Is there or is there not a transition zone there?

2390

A. I am sure there is a small transition zone there. I am not positive how large it is. Maybe you know how large it is. I have no particular idea, myself.

Q. Well, in the interpretation of logs, isn't it a fact that when you start getting a decrease in resistivity that reflects an increase of water saturation? A. Not necessarily, no.

Q. Well, let me add to that question. When your SP shows sand, isn't that a fact, that as your resistivity decreases steadily that is indicative of a higher water saturation? A. It is possible, but it is not necessarily so.

Q. Well, what else could it be? A. Permeability.

Q. I should like to read a section from a paper prepared by Mr. Tixier, who is the same author—rather, who is the

same Tixier that Mr. Olson has attested to as being a competent geologist and well known in the field for his log interpretations.

Mr. Deakins: Mr. Examiner, neither Mr. Tixier nor Mr. Lewnes have been sworn, and therefore I object to this as pure hearsay.

Mr. Lewnes: I intend to show this statement to the witness and ask him whether he agrees or disagrees with what is contained on this paper.

2391

Mr. Deakins: Well, it is not proper to read it into the record first because those things get turned around to be evidence, and that can bring on reversal error.

Mr. Lewnes: In order for me——

Mr. Deakins: It is not produced under oath in the hearing and subject to cross examination.

Presiding Examiner: Mr. Lewnes, I think maybe you ought to show it to the witness first. Show him what you are going to read.

Mr. Lewnes: All right.

(Confers.)

Mr. Deakins: It is all right with me.

By Mr. Lewnes:

Q. The paper I want to quote from is titled "Evaluation of permeability from electric log resistivity gradients," by M. P. Tixier. In that paper, under the heading of "Gradient of Resistivity," it reads: "Figure 1 is an example of a log recorded opposite a sandstone where the water saturation increases progressively with depth. A transition zone can be seen on the resistivity log between A and B, where the curve is close to a straight line."

Now, I hand the copy of this paper to the witness and refer him to the Figure 1, and ask if that figure appearing

on there showing the resistivity curve does not in fact compare similarly with the resistivity curve on the log you are

2392

now discussing.

Mr. Deakins: Now just a minute, Mr. Witness. I object to that, Mr. Examiner, as not proper cross examination. It is incompetent, irrelevant and immaterial to prove any fact in these proceedings.

Presiding Examiner: Well it has been the experience of this Examiner, which has been limited, that no two logs ever look alike, but that the general knowledge obtained from looking at a number of logs out of a particular field gives you a general knowledge.

Mr. Lewnes, when was this paper written that you are now referring to?

Mr. Lewnes: Let me see if there is a date on it, Your Honor.

Mr. Deakins: What is it published in, do you know?

Mr. Lewnes: Let me find out.

Mr. Deakins: Mr. Examiner, the reason I objected: This may have been part of a letter that Mr. Tixier wrote to his mother, for all I know. And until there is some background shown that this was published as an—let's see—an opinion of an expert is accepted in the industry as the proper way of interpreting these things. I just don't think it is material. I don't think it hurts us actually. I know what Mr. Lewnes is getting at. But I hate to see the record cluttered up with a lot of things

2393

that are just sidebar statements of somebody that isn't here to defend it or say that he even told the truth then.

Presiding Examiner: Well, I gathered what Mr. Lewnes was doing was to ask this witness about this, and I gathered from the statement—the witness said that he recognized

the author of this statement as being a man of experience in the reading of an electric log.

Now I think it is true—and I am sure Mr. Lewnes will agree with this—that the log that the expert is interpreting —I don't even know what field it is from or what state it is from.

Mr. Deakins: It may even be a coal mine, Mr. Examiner. That is the point I make.

Presiding Examiner: Well,——

Mr. Lewnes: I think the log itself indicates—rather, the Figure 1 indicates electric log of Layton, Oklahoma, sand.

Mr. Deakins: You can't swear to that, Mr. Lewnes.

Mr. Lewnes: If we were going to go through the whole article—we can certainly show he is talking about a gas bearing sand.

Mr. Deakins: Who can say that under oath in this hearing? I can't. I know you can't. Only Mr. Tixier can say that.

2394

Presiding Examiner: Well, the witness on the witness stand is——

Mr. Deakins: Mr. Examiner, if this witness knows about that field, that is something else again. He could ask him if that appears to be a typical log from that particular field, if that is a gas well. As I said, it may be a coal mine or even an iron mine.

Mr. Lewnes: Mr. Examiner, if we are going to restrict all our questions and comparisons to this particular field, I think the record clearly shows that the witness has gone far afield in other fields to show what his abandonment pressures—what his recovery factor is going to be based on abandonment pressures of some other wells in some other field.

Mr. Deakins: Well, Mr. Examiner, I have no objection—

if we stay within this witness's knowledge, I have no objection.

Presiding Examiner: Well, hand the paper to the witness.

(Mr. Lewnes hands the paper to the witness.)

Presiding Examiner: Now then, ask your question now of the witness.

Mr. Lewnes: All right.

By Mr. Lewnes:

Q. Are the log characteristics shown in Figure 1,

2395

on that Figure 1, between the designated area A and B which Mr. Tixier has said is a transition zone—does that not compare or is that not practically identical with the log characteristic as shown on the W. Petitjean and No. 2, Klumpp D. sand, between the top and bottom of your net pay?

Mr. Deakins: Mr. Examiner, can I take this witness on Voir Dire?

Voir Dire Examination

By Mr. Deakins:

Q. Mr. Witness, do you know as a matter of fact that that is a log from an oil or gas well? A. No, sir, I do not know.

Q. Did you ever see that before in your life? A. I don't remember ever seeing it.

Q. Do you know where—is there such a field to your knowledge known as the Layton Field—L-a-y-t-o-n? A. I know nothing about the Layton Field personally. There could very well be a field by that name Layton.

Q. You don't know that there is a Layton Field, do you? I mean— A. I have never seen it, no, sir.

Q. Do you know there is a Layton Field in Oklahoma?

(2395)

A. I have no knowledge of a Layton Field, that I know of personally.

2396

Q. Now did you personally observe any of Mr. Tixier's interpretation of any particular log, to know whether or not his interpretation was correct in your opinion? A. I haven't checked this particular example, no, sir.

Mr. Deakins: I object to this as improper cross examination, Mr. Examiner, and on the other grounds which I stated previously.

Mr. Lewnes: Mr. Examiner, we don't mind the witness's being led, but I think we have gone a little too far. But we will withdraw the question. I think we have another question we can ask the witness.

Mr. Deakins: I wasn't leading the witness, Mr. Examiner. I was trying to lay the foundation which counsel for the Commission failed to do.

By Mr. Lewnes:

Q. Mr. Olson, you have just stated that the decrease in resistivity on the log under discussion could be caused by a change in permeability? Isn't that what you just stated?

Mr. Deakins: That is not the Layton log.

Mr. Lewnes: No,——

Mr. Deakins: The one the year before?.

Mr. Lewnes: W. Petitjean and No. 2.

The Witness: No, I don't think I expressed it in

2397

quite that same manner that your question is——

Mr. Lewnes: Well, Your Honor, I think this is a very important point. I think if we have to, that we should go back to this thing and have the reporter read exactly what the witness stated.

Mr. Deakins: I agree with you.

Mr. Lewnes: Because I think I correctly stated what his answer was.

Mr. Deakins: I agree with you, Mr. Lewnes. Mr. Examiner, I so move.

Presiding Examiner: Can you find the question and the answer, Mr. Reporter?

(Question and answer read.)

Q. Now my question, Mr. Olson, was: Wasn't it your testimony that a decrease in resistivity on the log under discussion could be caused by and perhaps you are objecting to the words "have a change in permeability".

Now wasn't that your testimony? A. I mentioned permeability mainly because the lower the permeability the higher the interstitial water would be, and the larger the permeability the lower the interstitial water would be.

Q. All right.

In other words, what you are stating now—and I

2398

believe you stated that yesterday: That the lower permeability samples have higher interstitial water? A. That is generally correct.

Q. Well, now, in this particular case, since you said it could be a change in permeability, would that be a decrease in permeability? A. It is entirely possible, yes, sir.

Q. So then it follows, again, that as your permeability is decreasing your connate water is increasing? A. Lower permeability will give you higher interstitial water.

Q. And are you saying now that that is what exists on that log, in your opinion? A. I don't know what exists in this log.

Q. Do you have the core analysis there for the Klumpp D. sand, on the W. Petitjean and No. 2? A. No, I do not.

Q. Apparently I am walking back and forth with it. A. Thank you.

(2398)

Q. Will you look at sample No. 38? A. Yes.

Q. Now that shows an irreducible water of 8 per cent, isn't that correct? A. According to this analysis, it so states.

Q. And does it not also state under that heading——

2399

under the heading of "Probable Production," it states "Water," isn't that correct? A. That is what this so states, yes.

Q. Now will you look at sample No. 31? Does that not indicate an irreducible water saturation of 19 per cent? A. That is correct.

Q. And under probable production, that also has water, isn't that correct? A. That is correct.

Q. One more sample.

No. 25: That has an irreducible water saturation of 33 per cent. And under the probable production, that also says "Water," isn't that correct? A. That is correct.

Q. Now, will you turn to the core analysis——excuse me one moment.

All right. Now will you turn to your Exhibit X-2 and tell us what you have indicated there for your connate water for the Klumpp A—that is your interstitial water or connate water? A. I used 34 per cent.

Q. Well, the problem I am having, Mr. Olson, is that if these core analyses indicate that the 8 per cent and the 33 per cent, they indicate that that is going to produce

2400

water, how is it that you show a connate water of 34 per cent and expect to get gas? A. I can't see any way of making any comparison with the material that he gave me in answering that question.

Mr. Deakins: Explain it, then, for the record.

Mr. Lewnes: Well, I believe we are talking about the same —we are talking about connate water. And if certain analyses show the connate water to be at a lower per cent than what he has shown on his exhibits and they don't expect to get gas, they expect to get water, how does he expect to get gas when he uses a much higher connate water?

The Witness: One reason why they expect to get water in the examples you have shown me is because it is below the gas-water contact—those samples that you indicated.

By Mr. Lewnes:

Q. Well did you use those samples in determining your connate water? A. I used the information that was presented in this entire report.

Q. Well, specifically, did you also use those samples that I have referred to? A. Those samples were evidently used to construct the curve of permeability versus irreducible water. And

2401

what I used in relation to the curve was all of the representative permeabilities that I considered in arriving at my interstitial water for this particular well—reservoir, I should say.

Q. And you used those curves to determine your connate water? A. What curves now are you talking about?

Q. The curves you just mentioned. A. This was one curve that I mentioned here.

Q. Oh, we are talking about those irreducible water curves? A. That is correct.

Mr. Deakins: You used all those, is that what you mean to say?

The Witness: Where——

Mr. Deakins: It is correct that you used all of them?

The Witness: Where this information was available, and

where I considered it to be representative of material that should be used "A" I used it.

Mr. Deakins: That wasn't what your last answer was. You see, you said "Yes."

The Witness: I used this curve in this particular case, which I think I told Mr. Lewnes.

2402

By Mr. Lewnes:

Q. Well, Mr. Olson, then, to clarify the entire matter now, the irreducible water samples that we referred to, that is with the 8 per cent, 19 and 33, they were used, I believe you testified, to make up the irreducible water graph which you have used? Now isn't that your testimony? A. These points were used in making up this particular graph that you have in question, yes.

Q. Which you have used? A. That is correct.

Q. And those samples were taken below the transition zone? A. They appear to be taken below the gas-water contract, yes, sir.

Q. And that would be below the transition zone, doesn't that follow? A. I would say—I am not sure.

Q. All right.

I might add that one of the samples was not even taken in that particular sand that you had in question.

Mr. Deakins: That is a point.

Mr. Lewnes: Nevertheless, that was still plotted on the graph, wasn't it?

The Witness: It was plotted on the graph, but was

2403

probably not particularly needed to construct this graph for the area that it encompassed.

By Mr. Lewnes:

Q. But it was plotted on the graph.

Mr. Olson, in your testimony, in 1959, at transcript 1470—and I will hand you a copy of that—you said you had not seen any evidence of water encroachment in reservoirs of this type. Do you recall that? A. If you will show me, yes, show me the transcript.

(Hands transcript to the witness.)

Mr. Deakins: Look at the date of that, to be sure you know what he is talking about.

Mr. Lewnes: 1470.

Mr. Deakins: Yes. I told him to look at the date of this.

Mr. Lewnes: Oh.

The Witness: I see this statement, yes.

Mr. Lewnes: All right.

By Mr. Lewnes:

Q. In other words, you made the statement that you had not seen any evidence of water encroachment in reservoirs of this type? A. (Nods.)

Q. Now my next question is——

Mr. Deakins: Now wait a minute. Mr. Lewnes, I object

2404

to that as a misstatement of the testimony of this witness, to which this witness nodded his head. What the witness said: "We have not seen any evidence particularly of water encroachment on reservoirs of this type."

Now, Mr. Olson, you are going to have to watch this, to be sure that you answer the question he asked you, and that the question, if he quotes your testimony—that then it is quoted correctly, because particularly it makes a lot of difference in my opinion, as the key word in that statement of this witness, which was not stated correctly to you.

(2404)

Mr. Lewnes: We have handed the witness a copy of the transcript each time we referred to any particular statement of his. If I misquoted him, the witness is free to read directly out of that transcript and state exactly what he said.

Mr. Deakins: I agree with you. I didn't intend to say that you meant to mislead the witness. But I want the witness to be careful of this, because it may make a difference. I don't know.

Mr. Lewnes: Right.

By Mr. Lewnes:

Q. My question, Mr. Olson is: Have you seen any water encroachment in the reservoirs lately, or since you made that statement, for Rayne field now?

2405

A. I have not noticed any form of major water encroachment in any of the reservoirs, no.

Q. Well, is it not a fact that all producing wells on Rayne field are producing water? A. Could you state what wells you have in—

Q. I am talking about all the wells in Rayne field. A. It is possible they are producing a small amount of water.

Q. Well, isn't it a fact that they are currenty producing water at a greater ratio than they were producing in 1959? A. I would not know unless you could state the fact, please.

Q. Well, before we get to your work papers, I will refer you to transcript page 1824, and ask you if I have not—

Mr. Deakins: Do you have a copy?

The Witness: No.

By Mr. Lewnes:

Q. And I ask you if I have not properly quoted this, or you can change it if I have. A. All right.

Q. That Mr. Marshall, at that page, said in effect that

performations in Nodasaria unit 9 No. 1 will have to be raised in order to shut off water. Now isn't that a fact?

2406

A. Yes, that is correct.

Q. And my question was that the wells currently show an increase in the barrels of water produced, we will say per million cubic feet of gas, than they had previously, and I believe your answer was that you did not know that to be a fact, is that correct? A. I said that I didn't have the data in front of me here to show what increase has come about. Iam not saying that I did not know that there was an increase, but I do not have that data to show me how much there was.

Q. Well, we have taken the work papers that Texas Eastern submitted, and rather than hand you all of these work papers and let you go through the computation, let me read a couple instances in the record and you can check these through the work papers and see if that is correct.

Mr. Deakins: Mr. Lewnes, are you reading the staff summary of the work papers or from the work papers?

Mr. Lewnes: No. We have taken the work papers and from these work papers—as indicated on these work papers, they indicate what the water production per barrels per month for—we have used the period of May 1961 because we had all of the information for that period. Now we have taken that and compared it with the figures on the work papers, of the barrels per million cubic feet for the same month in 1960 and have come up with a ratio which indicates

2407

that the water production during May 1961 in relation to the volumes produced is much higher than the ratio of water produced in 1960, again in relation to the volumes of gas produced.

So what I just want to do is read a couple of these in the

record or as many as you like and the witness can check that and tell us whether we have been accurate or not.

Mr. Deakins: Well, I object to it, Mr. Examiner, if he doesn't read them all.

Mr. Lewnes: Well, we will read them all, then.

Presiding Examiner: Well, let's do it, then, after the morning recess.

Mr. Lewnes: O.K.

(Whereupon, at 11:30 o'clock a.m., a recess was taken until 11:40 o'clock a.m. on the same day.)

2408

Presiding Examiner: Are you ready, Mr. Lewnes?

Mr. Lewnes: Yes, Your Honor.

I should now like to read into the record the following figures, and these would be subject to check by the witness.

The first set of figures I would like to give——

Mr. Deakins: Mr. Examiner, can we go off the record a second?

(Discussion off the record.)

Mr. Lewnes: What I am going to read in is the water production per barrel per month, and this is for May 1960.

In other words, I am going to read in the number of barrels produced from the various units—for the various wells in the various reservoirs. And these figures are for the month of May 1960. I then shall read the water barrels produced for May 1961 from the very same units.

All right?

Now, beginning with the Nodasaria A reservoir.

Unit 1—and then I will give the production figure—390 barrels.

Unit 2, 330 barrels.

Unit 3, 341 barrels.

Unit 4, 377 barrels.

Unit 5, 420 barrels.
Unit 6, 300.
Unit 7, 558.

2409

Unit 8, 377.

And Unit 9, 2,001.

Mr. Deakins: The witness is looking at a document—"Gas Well Deliverability Document". We thought it had it on that. And he didn't get an opportunity to write that down, Mr. Lewnes.

Mr. Lewnes: Pardon me.

Mr. Deakins: He didn't get an opportunity to write those barrels down. Could you read those?

Mr. Lewnes: All right. Could I get off the record and I will read them back again?

(Discussion off the record.)

The Witness: Are these barrels per month? This is barrels per month?

Mr. Lewnes: That is right. And this is for the month of May, 1960.

The Witness: All right.

Mr. Lewnes: Now, we go to the Homeseekers D-2.

And for Unit 2, it shows zero water production during May 1960.

Now, continuing with the same date.

Homeseekers E, Unit 1, 690.
Unit 2, 279.
Unit 3, 270.
And Unit 4, 341.

2410

Northeast Fault Block.
Unit 1, 42.
Let me go to Homeseekers E.

Southeast Fault Block.
Unit 1, 3,950.
Homeseekers E, South Fault Block, Petitjean, 8.
Klumpp A—this is Quebodeaux Klumpp A, Unit 1, 20.
The Witness: How much was the Quebodeaux well again, please?
Mr. Lewnes: Pardon me?
The Witness: How many barrels did you announce on the Quebodeaux well?
Mr. Lewnes: 20.
Now Klumpp D. Edward Arceneaux Unit 2, 52.
We have Elton, Arceneaux Unit 1, 48.
W. Petitjean Unit 1, 121.
And finally, the W. Petitjean and Co., Unit 4, 136.
Now, I would like to give you the comparable figures for the same month, but for the year 1961.
Nodsaria A, Unit 1, 209.
Unit 2, 252.
Unit 3, 299.
Unit 4, 258.
Unit 5, 350.
Unit 6, 273.

Unit 7, 280.
Unit 8, 486.
And Unit 9, 3,090.
Now, Homeseekers D-2 Unit 2, 240.
Homeseekers E, Unit 1, 338.
Unit 2, 1,000.
Unit 3, 676.
Unit 4, 234.
Northeast Fault Block, Unit 1, 480.
Now, Homeseekers E, Southeast Fault Block, Unit 1, 14,632.

For the Homeseekers E, South Fault Block, Marie Petitjean, nothing.

Now, for Klumpp A, Quebodeaux, Klumpp A, Unit 1, 186.

Klumpp D, Edward Arceneaux, Unit 2, 280.

Now, Elton Arceneaux, Unit 1, 248.

And the W. Petitjean, Unit 1, 84.

And W. Petitjean and Co., Unit 4, 48.

Now, if we take that water production and correlate to the gas production for the given periods for those units, it is the staff's statement, and you can check this, that the majority of the units have produced more water in 1961 than in 1960 in relation to gas production.

I guess we will have to leave it there until he gets a chance to check it.

2412

The Witness: Have you asked me a question now, or is this just a statement?

Mr. Lewnes: I made a statement, and you can check that, whether we are correct or not.

The Witness: Could you tell me how much more water did you come out with?

Mr. Deakins: You mean total?

The Witness: Yes.

Mr. Lewnes: Well, in other words, at times we have gotten perhaps twice as much water produced in 1961 than was produced in 1960. In the majority of cases we are getting more production of water now in relation to the volumes of gas produced than you were getting in 1960.

That is the crux of the question.

The Witness: But I mean where were you getting this twice as much water? I see in lots of cases here the actual water in '61 was less than '60.

Mr. Lewnes: Well, when you relate it, though, to the gas produced.

The Witness: (Nods.)

Presiding Examiner: I think he is talking about the percentage of water.

Mr. Lewnes: Yes, sir.

Mr. Deakins: Water as to gas.

Presiding Examiner: Yes.

2413

The Witness: Subject to check, I will.

Mr. Deakins: Why don't you just wait until you check it then, instead of giving him an answer that we will have to change?

Mr. Lewnes: Right.

By Mr. Lewnes:

Q. In your Exhibit X-2, page 2, what is the interstitial water which you have indicated for the Nodasaria A? A. I have used 14.9 percent.

Q. With that percentage, you nevertheless expect—strike that.

Now, if the interstitial water for the Nodasaria A is only 14.9 percent as you have indicated, wouldn't it be unlikely that the Nodasaria wells would produce water? A. Would you rephrase that question, please?

Q. Well, I will have the recorder repeat it, the question. Will you read the question?

Presiding Examiner: Will you read the question, Mr. Reporter?

(Question read.)

The Witness: The interstitial water has no bearing on your question at all.

By Mr. Lewnes:

Q. Well, what is this water that is being produced in the Nodasaria A presently?

A. I can enlighten you on what that water is.

It is a fact that in these gases at these depths, that these gases contain fresh water vapor, and as the gas comes up through the tubing this water vapor condenses out of the gas and that is what the figures are that you have given me in the past here, of how much water is actually condensed out of the gas.

Q. Well, then, is that the reason then that Mr. Marshall at page 1824 says that perforation as in Nodasaria Unit 9 will have to be raised in order to shut off the water? Is that your understanding of the situation? A. You were previously referring to the Nodasaria A. Now, could you rephrase your question a little more clearly on what you are driving at now?

Q. Well, now, isn't Nodasaria Unit 9 in the Nodasaria? Now, Mr. Marshall has stated that perforations in Nodasaria Unit 9, No. 1, will have to be raised in order to shut off water, and I ask: Is the reason for these perforations which Mr. Marshall has given predicated on what you have testified as to what that water is that is being produced? A. Certainly part of that water that is shown in that particular well is this water vapor that I have stated.

However, it is possible that some of this water could be formation water. It is also possible that it was a poor cement job in the well. It is also possible the well might

have a casing leak. It could be for various reasons. I don't know definitely why or where that water is probably coming from.

Q. But you can say definitely that none of that water is interstitial water? A. Interstitial water is not produced. It is retained in the reservoir.

(2415)

Mr. Deakins: Well—I move to strike the answer as not responsive.

The Witness: Well, I would like to clarify, then, and say no, this is not interstitial water.

By Mr. Lewnes:

Q. Mr. Olson, in your Exhibit X-2, page 2, at line 5, you have used the term "estimated average thickness."

Could you define that? A. The estimated average thickness as I have used it here: That number is determined by dividing the number of acres into the number of acre feet, in that particular reservoir.

Q. Well, is the term "estimated average thickness" synonymous with net pay? A. Yes. The average thickness for any particular pay that you want to refer to here is the average thickness of the sand that I have found over the entire reservoir.

Q. Now, how do you determine this estimated average

2416

thickness or net pay for a particular well, an individual well? And if you like, you can pick out an individual well to better explain your answer, if you would. A. I don't determine it by an individual well. I just told you how it was determined.

Q. Well, don't you get the net pay in a particular well in a particular reservoir before you determine what your net pay is for your entire reservoir? A. Yes, you have to, of course, determine the net pay in each well.

Q. All right.

Now, could you describe how you determine your net pay in a particular well which is later used to determine the net pay for the entire reservoir? A. I pick off my——well,

could you rephrase it and tell me just exactly what steps you want me or how you want to describe this, sir?

Q. In relation to what logs you use, et cetera. A. I use a combination of both the electric log and micro log, if available. Also take in consideration the core analyses. And from using all three of those sources I come up with the net pay for that particular well.

Q. All right.

Now—well, in relation to electric logs and micro logs, which do you prefer to use or do you use them interchangeably

2417

or selectively? A. I use both logs if available on any particular well.

I found that in this particular field and for these particular reservoirs the micro log was a very good tool and a good check point for the electric log.

Q. Well, now, coming down to actually counting the feet of net pay in a well, do you count it on your micro log or your electric log? A. In the majority of the cases where I had micro logs, I used the micro log.

Q. Well, you said in the majority of cases. Could you give me an example when you would not use a micro log, if you had a micro available, and you might refer to the use of an electric log or something else? A. Well, it just depends on my own best judgment of how the log was run, and if it was run correctly and had the certain characteristics that I am familiar with, that would determine using one log over the other.

Q. Now, are you the same Mr.——oh.

One previous question. Is the term "net thickness" synonymous with the term "net pay"? A. In this particular case the estimated average thickness that I have used in Exhibit X-2, on page 1, has been determined from the net pay that I have found in the

2418

various logs.

Q. Well, I mean, in a general sense used in the trade by geologist, when a geologist uses the term "net thickness" he uses it interchangeably with net pay. That is, you might call it net pay or net thickness, but he is talking about the same thing generally?

Mr. Deakins: That is objected to as immaterial. The question is what this man used and not what is used in industry.

Mr. Lewnes: I believe the witness is a geologist, well versed in the terminology of the industry.

Mr. Deakins: I have no objection——

Mr. Lewnes: I can rephrase it.

By Mr. Lewnes:

Q. You have testified that when you use net thickness you use it interchangeably with the term "net pay"? A. Most generally, I do, yes.

Q. Now, are you the same E. A. Olson who testified in Docket No. G-11024 in 1960, which has been referred to as the CATCO case? A. Yes, I am.

Q. Now, I ask you if this is a proper quotation from your testimony in that proceeding as it appears on transcript page RE-1242. And as soon as I read it I will hand you a copy of it to check it. You state: "The reason I say that,

2419

Mr. Geneau, is that anybody that has a degree in energy" —and I believe that was changed by transcript correction, changed to "engineering"—"or geology is taught how to read an electric log, and I believe most anybody that has had experience and has worked with electric logs should read the log the same way."

Mr. Deakins: I object to just reading the quote, because it is out of context. It isn't the whole quote of an answer to a question that was propounded to this witness.

Proper cross-examination would indicate that the witness be advised of the question, plus the full answer.

Presiding Examiner: Well, the witness has the transcript in front of him now and he may—he is refreshing his memory from the full context of what the question was and his answer was.

Mr. Deakins: That is right.

Presiding Examiner: To that.

Mr. Deakins: I didn't want to be coaching this witness. I just wanted to be sure he knows what is before him.

Presiding Examiner: Well, I gather from his demeanor on the witness stand he is not unfamiliar with testifying before the Federal Power Commission at least.

Mr. Deakins: No, he has been here before.

Unfortunately, I have never seen this Tennessee transcript before. I have no idea of what is in it.

2420

Presiding Examiner: I have not seen them, either.

Are you ready, Mr. Olson?

The Witness: Yes.

Presiding Examiner: The witness is ready to answer.

By Mr. Lewnes:

Q. Did I properly quote you, Mr. Olson? A. Yes, as far as the quote was concerned.

Q. Well, is there anything you would like to add to that quote? A. Well, as any answer is given about anything, I would just like to say, as Mr. Deakins has pointed out, a lot of it would refer to exactly what the question was and what they were driving at what point they were trying to get across at that particular time.

Q. Well, so there won't be any misconstruction, would you care to read the question and the entire answer into the record? A. Well, I would have to start at the top of the page. Wait a minute, now.

Starting with the question by Mr. Geneau:

"Am I not correct, Mr. Olson, that whether uses core analyses or electric logs with respect to, say, determination of porosity, permeability and interstitial water content, perhaps among other things that a great deal of judgment enters into the determination of these elements on the

part of the person making the estimate?"

The answer: "That is correct, and I have been working in this area for some 15, 16 years and have determined through that time interval just what source, that is the best to rely on, whether it be the electric log or the core analyses, and also having studied the field throughout this whole general area, it gives one advantage that he worked in an area this long to place judgment on some of these factors."

Question: "Now, this judgment element or factor also enters in with respect to determination of the structure and net pay, too, does it not?"

Answer: "I think we are getting a little bit vague on what he means now by judgment. The reason I say that, Mr. Geneau, is that anybody that has a degree in engineering or geology is taught how to read an electric log and I believe most anybody that has had experience and has worked with electric logs should read the log the same way."

Now, that has somewhat of a broad meaning.

Mr. Lewnes: Thank you.

By Mr. Lewnes:

Q. Now, Mr. Olson, I should like to read certain figures here again as appearing on the work papers submitted to the staff and ask you if this is not a proper summary—actually it is not even a summary. Actually they are figures

2422

taken off the work papers and summarized in our own tabulation. And I ask you if these figures are not correct figures as appearing on the work papers submitted to the staff. A. Now, could you—excuse me a minute. These work papers are my work papers, do I understand, or somebody else's or what?

Q. Well, you have testified that in arriving at your reserves here you used all available material given to you both from the Continental and some material you got from Louisiana and some you got from Texas Eastern and some material you got from your own files. A. All right.

Q. Now, what I am reading from is from the material that was submitted to the staff which we were told was part of the background upon which you made your calculations here.

Mr. Deakins: Did he submit this, Mr. Lewnes?

Mr. Lewnes: Texas Eastern submitted all this. This witness submitted his own work papers, these work papers, a part of the overall work papers, which this witness said he had available to him which he apparently looked at and made certain determinations as to what the ultimate reserves were here.

Mr. Deakins: Well, could you state what those are? Because there is nothing here that shows that the witness actually did look at all these. I don't know.

2423

Mr. Lewnes: Well, the witness— I believe the testimony in this proceeding has been, and the witness has verified that just now——

Mr. Deakins: As you said, that is right.

Mr. Lewnes: Yes. I am going to identify those papers.

Mr. Deakins: O.K.

Mr. Lewnes: Now, what I am going to read off, or at

least where I have taken this information from, has been from Mr. Olson's work papers and from the Continental Oil Company, new well completion data, submitted, to us by Texas Eastern as part of the overall work papers upon which this reserve was predicated.

Mr. Deakins: Have you seen those, Mr. Olson? What he just referred to.

The Witness: I believe I have, yes, sir.

Mr. Deakins: O.K.

Mr. Lewnes: Now, I am going to refer to the specific reservoirs and the wells there, and then I am going to give the net thickness which you have used, Mr. Olson, and the net thicknesses appearing on Continental Oil's papers that I have just referred to.

And you can check this and state whether this is not correct.

Now, beginning with the Nodasaria A, the W. Petitjean Well No. 2, your work papers show a net thickness of 86,

whereas Continental's shows 97. This is 86 feet and 97 feet.

Mr. Deakins: Just a minute now. Was that No. 2?

Mr. Lewnes: No. 2, well 2.

Mr. Deakins: Now, Nodasaria A.

Mr. Lewnes: Nodasaria A. I say Olson's net thickness, 86 feet, and Continental's, 97 feet.

T. G. Petitjean, Well No. 1, Olson's, 102 feet, Continental's, 85 feet.

G. Mouton, Well 1, Olson's, 105 feet and Continental's, 86 feet.

A. R. Branchard, Well 1, Olson's, 87 feet and Continental's, 69 feet.

D. Cormier, Well No. 2, Olson's, nothing, and Continental, 34.

E. Dupuis, Well No. 1, Olson's, 69, Continental's 62.

C. Dugas, Well No. 1, Olson's, 140, Continental, 109.

L. Cormier, No. 1, Olson's, 84, Continental's, zero.

Mr. Deakins: Mr. Lewnes what was the Dugas well number?

Mr. Lewnes: One.

Mr. Deakins: The one just before that.

Mr. Lewnes: One.

Mr. Deakins: I am sorry to interrupt you.

Mr. Lewnes: O.K.

2425

R. E. Babmeaux, No. 1, Olson, 41, Continental, 38.

Now, we go to the Homeseekers E. That is the Homeseekers E reservoir.

J. S. Arceneaux, Sr., No. 1, Olson's, 134, and Continental's, 121.

D. Cormier, No. 1, Olson, 52, Continental, 44.

T. G. Petitjean, No. 2: Olson, 114, Continental's, 106.

W. Petitjean 3, Olson, 96, Continental, 86.

Ed Arceneaux, No. 1, Olson, 118, and Continental, zero. When I say zero, it doesn't mean they have indicated zero. It means that we just have that before us. We haven't been given that figure. In other words, when I refer to zero, it means we just don't know what they are using.

Now, we don't have any for T. A. Mache No. 1, and we don't have any for the M. Petitjean No. 1, which Mr. Olson has indicated in his work papers is faulted.

Mr. Deakins: You mean you don't have any for either Olson or Continental?

Mr. Lewnes: That is right.

Now, we go to the Homeseekers D-2 reservoir. And the E. Navarro, No. 1—we don't have anything for either Olson or Continental.

Perhaps what I should do is just go down and give the ones we can make a comparison, because the others aren't

2426

available.

We go down to the Klumpp D, W. Petitjean No. 1—I am sorry, strike that. We don't have a comparison there.

We go down under the Klumpp D to the Elton Arceneaux No. 1, Olson is 39 and Continental is 38.

There is one other one here. I will have to qualify it.

Under the Homeseekers D-2, the M. Navarro, 1-A: Mr. Olson's papers indicate 27 feet of net thickness with a question mark.

I am sorry, you forget about that question mark. We have a comparison. Mr. Olson shows 27 whereas Continental shows 30.

That is the total figures. And the only thing we are asking of this witness: If it is not a fact that these are correct figures as shown on the work papers submitted to the staff.

Mr. Deakins: Do you mean——I object to that, Mr. Examiner. That is an indirect way of getting in an estimate of Continental that is not subject to cross-examination, not under oath, and not made in this hearing room.

Mr. Lewnes: Mr.——

Mr. Deakins: Now, you see what I mean? He says yes, that is correct. Then it goes in there as an estimate by Continental, which isn't the same as his. If we want to

2427

strike this out, I can sure do that.

Presiding Examiner: What I understood Mr. Olson to say was that he had Continental's work papers—

Mr. Deakins: Available.

Presiding Examiner: Yes.

Mr. Deakins: That is right.

Presiding Examiner: At the time. And any other data pertaining to these various departments.

Mr. Deakins: That is right.

Presiding Examiner: When he made his estimate or got up this estimated average thickness here on his exhibit X-2

Mr. Deakins: That is right.

But, Mr. Examiner, if that goes in, then I have to go back and prove he didn't rely on it. The burden of proof is on somebody else.

Presiding Examiner: He indicates that ~~he~~——

Mr. Deakins: He didn't rely on. He said he had them.

Presiding Examiner: He had it available to him.

Mr. Deakins: All right. But then that proves an estimate that is not supported.

Now, I don't think the Examiner will rely on it. But I have been in a lot of these administrative proceedings, particularly before the Labor Board, and you get caught with a lot of things that you wish you would never let get in at all. And I kind of hold a tight rein on all my witnesses

2428

and also on the other side, if the Examiner will note that.

Presiding Examiner: The witness will have had an opportunity to examine these work papers to which staff counsel have referred. Before we get to the redirect you can straighten it out there to suit your convenience.

Mr. Deakins: I will do that over the noon hour, Mr. Examiner.

By Mr. Lewnes:

Q. Mr. Olson, all factors remaining constant again—this is somewhat similar to a couple of questions I have given you previously. If you use a lower net sand thickness, and again all factors remaining constant, you ultimately would arrive at a lower reserve estimate, isn't that correct?

Mr. Deakins: Now, that takes into consideration porosity, permeability and everything?

By Mr. Lewnes:

Q. Keeping all those things in mind. In other words, if you make up a reserve estimate and leave the reserve estimate exactly the way it is, you have a final reserve figure. Now, if you just change the net sand thicknesses which you used in this reserve estimate, lower, that is, from the ones you have, will that not result in a return estimate lower than what you have indicated?

Mr. Deakins: Mr. Examiner, I object to that because

2429

the question will have no probative value. And I will explain to you how.

On this diagram that was put on the board yesterday, where they had a thing that looked into a couple markup here, they showed this water down here. Now, what are you going to take the 10 feet off of or the least amount off of? Off the top or off of the bottom?

If it is off the bottom, this witness said this morning if that were included there might be five percent more gas in these reservoirs. If you take it off the top, you may be taking the best part of it off.

Obviously, as the staff has been trying to prove this morning, there is some shale in one of these reservoirs, a little bit, or else the core samples didn't come out properly.

Are you going to take that 10 feet out? If you do—that is why I saw it has no probative value.

Mr. Lewnes: Mr. Examiner, this is a theoretical question. Irrespective of whether you take the 10 off the top, the bottom or the middle, is it not a fact that the reserve estimate will ultimately be lower? It is a theoretical question. This witness can certainly answer it.

Presiding Examiner: I gather what he says is that everything else being exactly the same, the testimony of all the conditions up to now being exactly the same, if in

2430

place of having 10 feet of pay sand you have only got 8, would that reduce your reserve estimate by two-fifths?

Mr. Deakins: Mr. Examiner, if I were the witness and was on my toes, I would take that reservoir that he has talked about this morning and exclude the shale and say it is the same and cut him up.

Now, that is why the question has no probative value.

Mr. Lewnes: Mr. Examiner, I submit that remarks of counsel are definitely leading and perhaps we shouldn't have the witness answer it. I think it is obvious and we certainly wouldn't want to have the witness now answer in accordance with the testimony of the counsel.

Mr. Deakins: I didn't testify, Mr. Examiner. But that is where I am trying to point out to the Examiner that the question is no good.

Presiding Examiner: Well, what I gather is now staff counsel says he doesn't care whether the answer answers or not.

Mr. Lewnes: That is correct.

Presiding Examiner: Have you another question?

Mr. Deakins: Mr. Examiner, I didn't intend to lead the witness. I just said what I would say if I were the witness.

Mr. Lewnes: If that is not leading the witness.

Presiding Examiner: Well, let me say this. It isn't

2431

like trying a law suit to somebody who is unfamiliar with the subject matter.

Mr. Deakins: No, sir. We have been through this thing two or three times before you. No.

2432

Presiding Examiner: Well, I have been around it 60 years.

Mr. Deakins: That is right.

Presiding Examiner: So I am on speaking terms with it at least.

Mr. Deakins: I am sure of that.

By Mr. Lewnes:

Q. Mr. Olson, do you have the micro logs for Quebodeaux No. 1? A. No, I do not.

Q. I shouldn't say the logs, I am sorry.

I will now hand you some logs and ask you if they are not the logs for the Quebodeaux No. 1, with specific reference to the Klumpp D. sand? A. Yes, these are the logs for that particular well.

Q. Now, would you give us the top and bottom of the sand as you have picked it? A. The top of the sand as I have picked it as at 11,279 feet.

I would pick the bottom of that sand at approximately 11,317 feet.

Q. Is there a gas-water contact at that bottom depth? Rather—strike that.

Is there a gas-water contact?

2433

A. There appears to be a gas-water contact present in this well.

Q. At what depth? A. The gas-water contract that was used for this particular reservoir was estimated at 11,308 feet.

Q. Well, where is the gas-water contact at that well? A. I would say it is within that vicinity that I mentioned.

Q. Well, isn't it a fact that your work papers show the gas-water contact for that well at 11,300? A. It is possible that I have put that down in my work papers, yes.

Q. Well, will you refer to your work papers and state if that is not a definite fact? A. I do have that note here. I just noticed that.

Q. And it is at 11,300? A. That is correct.

Q. Now what is the net pay that you have used for this interval? A. I used 21 feet.

Q. And what log did you get that off of?

A. I am not positive which log I actually got it off of. I probably, as I said previously, used the micro log in connection with the electric log.

2434

Q. All right.

Will you look at the micro log for that same interval? A. I have it in front of me.

Q. Isn't it a fact that that micro log shows non-permeable zones in that interval? A. Could you indicate where you mean, what part of that log you mean where the non-permeable zones?

Q. May I have the log, please?

Mr. Olson, a specific reference now to the interval between 11,280 and 11,286, and in the interval between 11,296 and 11,300, is it not a fact that that micro log indicates non-permeable zones within those designated footages? A. I can't say exactly the reason for the micro log not indicating the entire sections to be porous. In my best judgment, looking at this particular reservoir, due to the clear characteristics of the self potential curve here, I assumed it to be all pay.

Q. Well, now, you assumed it to be all pay. But isn't it a fact, if you read the micro log alone, standing alone, that that does show between those intervals non-permeable zones?

Mr. Deakins: Mr. Examiner,——

The Witness: Mr.——

Mr. Deakins: Just a minute. The witness did not say

2435

he relied on that alone.

Mr. Flaningam: That isn't the question.

Mr. Lewnes: That is not the question.

Presiding Examiner: The witness may answer.

Mr. Deakins: I am sorry.

Presiding Examiner: Do you want the question read?

The Witness: Yes, I believe so.

Mr. Deakins: I thought it was changed by that other statement.

Presiding Examiner: Will you read the question, Mr. Reporter?

(Question read.)

Mr. Deakins: Now if you will read the answer just immediately preceding that, the Examiner will see what I mean.

Mr. Flaningam: But he didn't answer the question.

Presiding Examiner: Well, he said before that that he assumed it all to be pay.

Mr. Deakins: He said when he looked at this other log—

Presiding Examiner: Yes?

Mr. Deakins: That he assumed it all to be pay.

Presiding Examiner: Assumed it all to be pay?

Mr. Deakins: That is right. What I thought he testified is that he looked at something else or used something

2436

else. I just didn't want the record to get off the track, Mr. Examiner.

Mr. Lewnes: The question pending, Your Honor, is that if you take the micro log and look at it alone—if Mr. Olson would pick up that micro log and look at it, isn't it a fact that by looking at that micro log it shows non-permeable zones within the designated footages that I have given to him.

The Witness: If you were to look at the micro log by itself, it is true that there is a small degree of characteristics on this micro log that indicates it not to be porous.

However, to elaborate on it, again, I have to say that my reason for getting the 21 feet to begin with—because I had

to use both logs, and also you have to base this judgment factor that I have been expressing from time to time.

By Mr. Leynes:

Q. Then, in effect, you used the electric log for this particular—for determining net sand thicknesses for this particular well? A. I used the combination of both, yes.

Q. Well, now, you mentioned porosity in relation to the micro logs.

Now, what is the purpose of the use of that—all right,

2437

what is the purpose and use of the micro log? A. Well, one of the main purposes of the micro log is to determine your porous sections in your sand.

Q. So isn't it a fact that the micro log has been developed primarily as a means for the accurate determination of permeable beds, where the SP log alone does not give a satisfactory answer? A. Here, again, you have to take into consideration how the log might have been run, whether some mechanical phase of it at the time might have changed the needle that makes the lines. You have to assume all this particular judgment in using a log. You just can't exactly use it on its face value all of the time, no.

Q. In other words, what you are saying is that some of these logs that you have had here aren't accurate and can't be relied upon? A. No, I am not saying that they can't be relied upon. I am just saying that you have to use your judgment and your knowledge when you are using a log.

Q. Just get back to this specific log, isn't it a fact that if you eliminated even the small degree, as you have put it, of impermeable beds shown on the micro log—if you had eliminated those from your reading of the electric log, you would come up with a net pay smaller than that which you have used for this well?

A. I did not eliminate any of the pay, so I will not state what it would be. I assumed it to be 21 feet. That is what I used.

Q. You calculated all, notwithstanding the facts as you have now indicated the micro log did indicate some impermeable beds? A. I believe that question has already been answered.

Q. I think we have one final question. Getting back to the recovery factor, Mr. Olson, isn't it a fact that in any presentation that you have made before this Commission on reserves other than a presentation for Texas Eastern, you have not used a recovery factor as high as 93 per cent in any of your reserve studies? That is again exclusive of any reserve study submitted on behalf of or for an application that Texas Eastern has filed?

Mr. Deakins: I object to the question, Mr. Examiner, as not proper and not correctly reflecting the witness's testimony. The witness when he came back this morning you will recall testified that he did not use any 93 per cent recovery factor, that he used an abandonment pressure. If he wants to ask about an abandonment pressure I have no objection to that. And that is the fact.

By Mr. Lewnes:

Q. Well, isn't it a fact, Mr. Olson, that from your testimony and exhibits here, you indicate that you will

2439

recover approximately 93 per cent of your gas in place? Isn't that a correct statement? A. I haven't checked it out. Could you tell me how you arrived at that figure?

Q. Are you stating that you don't know how to calculate what percentage recovery factor——A. No, I am not stating that. I am asking you how you got it.

Q. What is your percentage recovery factor of the initial gas in place which you have indicated on your exhibit? A. I did not use a recovery factor in my exhibit. I used an abandonment pressure of 515 pounds.

Q. All right. We are going to have to go through this tediously. Let's go to Exhibit X-2, page 2, lines 16 and 18, under total column "m."

Now if you divide line 18 by line 16, don't we come up with a 93 per cent recovery? A. If you are asking me to divide those two figures, I would come up with approximately 92.4 per cent.

Q. Now my question is: In any of your other reserve studies submitted before this Commission in any proceeding not involving Texas Eastern, do you show a recovery factor as high as 92.4 per cent which you have just attested to?

2440

Mr. Deakins: Now, Mr. Examiner, I object again to the question because it doesn't assume the same pressure base. If it did, then you are comparing apples with apples. Otherwise you are comparing apples with oranges. If you say 1,000 pound—if he testified to 1,000 pound abandonment pressures in other cases and 500 here, that would make a lot of difference in the percentage. It is just something to clutter up the record with. It doesn't prove anything.

Presiding Examiner: As I understand his supplemental testimony this morning, Mr. Lewnes, he said that he used an abandonment pressure of 500 pounds to arrive at the estimated recoverable gas that is shown there on line 18.

Mr. Lewnes: We won't pursue this any further. We have no further questions at this time. Thank you.

Presiding Examiner: We will take a noon recess at this time.

(Whereupon, at 12:37 o'clock p.m., a noon recess was taken, to reconvene at 2:00 o'clock p.m.)

2441

AFTERNOON SESSION

E. A. Olson

resumed the witness stand and testified further as follows:

Presiding Examiner: Mr. Lewnes, did you have any more witnesses, or have any more questions of this witness?

Mr. Lewnes: No, Your Honor. We concluded our cross examination. Thank you.

Presiding Examiner: He is your witness, then, Mr. Flaningam.

Mr. Flaningam: Thank you. I have a few questions.

FURTHER CROSS EXAMINATION

By MR. FLANINGAM:

Q. Mr. Olson, you have testified that the Homeseekers D. 4 sand has not been tested, isn't that correct? A. That is correct, yes.

Q. Isn't it a fact, however, that this sand was tested in the Navarro A. 1 well, and that this test resulted in salt water production? You know the well to which I am referring, do you not? A. I know the well to which you are referring, yes.

I would like to ask you at this time, before I answer your question, at what interval was that particular test made.

Q. Well, I don't think it is material to answering

2442

a question as to whether or not there has been a test in the interval.

Now hasn't this sand been tested in this well? That is my question. A. I believe there has been a test in this well, yes.

Q. And it tested salt water, didn't it? A. If the test had been made in the water part of the sand, it probably would have tested salt water.

I have got to know in the interval that you are talking about.

Q. Well, you are not familiar, Mr. Olson, with what tests were made in that well? A. I am familiar, or it seems to come to my mind, there was a test made on this well, but I don't remember that the interval that was made at this time.

Q. It was made in this sand—Homeseekers D. 4 sand, that is right, isn't it? A. I say that I am familiar that a test was made in the Homeseekers D. 4 sand.

Q. But you don't know what the results were, or what the interval was? A. I can't remember the interval that it was tested or the actual results of the test.

Q. And I would assume—I suppose it is rather

2443

elementary, isn't it, Mr. Olson, that the test that was made was with a view that the sand was productive in the interval where the test was made? Wouldn't you assume that that was so, that that was the objective and the theory on which the test was made A. Most generally that is why a test is made, to determine what the sand—the content of the sand.

Q. We could just agree that when they make these tests, initial drilling of wells, that that is why they are testing, isn't it? It is on the theory they think the particular sand, or at interval where they make the test, is productive? A. That is right, yes.

Q. Now during your testimony, I think both on direct and cross examination, there has been reference made to your use of the irreducible water factor as your connate water factor or interstitial water factor that you have used in your reserve calculations, reflected in Exhibit X-2? A. Could I have that question reread, please?

Presiding Examiner: Reread the question, Mr. Reporter.

Mr. Flaningam: I can restate it. Just strike it and let me try it again.

2444

By Mr. Flaningam:

Q. During the course of your testimony with respect to Exhibit X-4, you have indicated that you have used for your interstitial water factor or connate water factor what you have termed what is known as the irreducible water factor of certain sands involved in your study? A. In certain of the sands, yes.

Mr. Deakins: Mr. Flaningam, you said Exhibit X-4. I don't think this witness had anything to do with X-4.

Mr. Flaningam: If I said X-4, I was mistaken. If the Reporter will correct it to X-2.

Mr. Deakins: X-2.

Mr. Flaningam: Thank you, Mr. Deakins.

By Mr. Flaningam:

Q. You would use the irreducible water factor for interstitial water content of a reservoir, would you not, only under optimum conditions? A. I don't quite understand your question, Mr. Flaningam.

Q. Well, let me see if I can make it somewhat more clearer. By using the irreducible water factor for your interstitial water content of a reservoir, as a general proposition, the effect on the reserves which you would calculate would be to derive the greatest possible reserve for a

2445

particular reservoir, would it not, so far as you take into consideration the water saturation of the sand involved? A. Well, if I understand your question, where I have the material available, such as I have expressed before on this irreducible water—and I considered the material relevant to this reserve—I would definitely use that material to the best of my advantage.

Q. Maybe I can approach it—— A. Or to the best advan-

tage of the reserve estimate, let's say, in arriving at the best estimate I could probably arrive at.

Q. You would certainly not use in any reserve study a connate water or interstitial water content factor that would be lower than the irreducible water factor as you have used the term in your testimony? That is right, isn't it? A. The factor that I would use, to begin with, would again have to be related to the material that I have available.

Q. Well, now, I understand that, and I think we all do. Now I am trying to get the thing on the table in pure theory, of calculating reserves, and I am directing my attention particularly to the water factor, the connate water factor that you would use. In no study, in no reserve calculation, would you use a factor that is lower than the

2446

irreducible factor calculated for the particular sand involved, would you? A. That is correct.

Q. So what you have done: You have used the lowest possible water factor that could theoretically be used in calculating the reserves in your study reflected in Exhibit X-2? A. No, that is not right.

Q. Insofar as water, I am saying. A. I have used the interstitial water per cent that I found to be the proper per cent to use with the available material that I had.

Q. Well,—— A. I mean this is the one that you use.

Q. Yes, but in certain sands and reservoirs, you have used the irreducible water factor as constituting the interstitial or connate water factor. That is correct, isn't it? A. Well, it is more or less one of the same things when you come right down to it.

Q. Well, have you finished your answer? A. Yes, sir.

Q. Maybe we better just—I don't like to spend so much time on this, but I certainly am becoming confused by your recent answer.

2447

Mr. Deakins: That was his answer to the question by the staff, Mr. Flaningam.

Mr. Lewnes: Excuse me. I think when he defined interstitial and irreducible water, he didn't define them as being one and the same. And it seems that his answer now is that they are the same.

Mr. Deakins: I thought he said this morning practically the same.

The Witness: I said they are closely related.

Mr. Flaningam: Well, I may have misunderstood the purport of your testimony.

Let me see if I can try to summarize this matter in the interest of expediting this examination.

By Mr. Flaningam:

Q. As I have understood your testimony, and particularly in response to certain of my questions, you have stated that the irreducible water factor as a general proposition represents the lowest water factor that could properly be used in any reserve study at any time. Now that is correct, isn't it? A. That is right, yes, sir.

Q. Now I have also understood that in this study of yours reflected in Exhibit X-2, you have with respect to several of the reservoirs used for the connate or interstitial water factor of the particular reservoirs factors

2448

that are exactly equivalent to the irreducible water factor applicable to those reservoirs, that is right, isn't it? A. That is correct, yes, sir.

Q. Then it follows—and possibly there is a question—this is the one question too many, Mr. Examiner, but does it not follow, Mr. Olson, that where you have used the irreducible water factor the result of that has been to use a factor that

would result in the largest reserve estimate possible so far as the water factor enters into reserve calculations? A. Yes.

Q. It necessarily follows, does it not, that you would use such factors under the assumptions that the most optimum conditions are anticipated in the reservoirs involved and in the subsequent production of the gas from such reservoirs? A. That is entirely possible, yes, sir.

Q. May I ask: Isn't it unusual to use in a reserve calculation the irreducible water factor for your connate or interstitial water content factor? A. No, I would not say it is unusual.

Q. Well, would you say, on the other hand, or the other side of that coin, Mr. Olson, that it is a common practice among engineers in your field, in estimating reserves in fields involving sands and reservoirs of the character involved in the Rayne field, to use the irreducible

2449

water factor for your connate water factor in such calculations? A. I would like to have that reread back, please.

Presiding Examiner: Will you read the question, Mr. Reporter?

(Question read.)

Mr. Deakins: I object to that question. No foundation laid.

Mr. Flaningam: Your Honor, I think it is a perfectly proper question in the circumstances.

Presiding Examiner: The witness said that interstitial and connate water was one and the same, and irreducible water was closely related to the two, and in the instance or the illustration here that was just used he used the same figure, the same percentage, that he found for irreducible or connate—interstitial or connate, and irreducible.

The witness may answer.

The Witness: I can only speak for myself here, that I would use it.

Now I presume other people would use it also.

By Mr. Flaningam:

Q. Your answer, then, to my question is that you do not have knowledge as to whether or not what you have done in this regard is a common practice for estimating

2450

reserves in reservoirs and sands of the character involved in the study reflected in Exhibit X-2? A. It may very well be. I don't have any particular knowledge in what you people might do.

Mr. Deakins: Mr. Examiner, that was the basis of my foundation objection right there. If he had asked him that question he would have gotten that answer and here we would be at this point already.

Presiding Examiner: We would be one question further down the road, wouldn't we?

Mr. Deakins: That is right.

By Mr. Flaningam:

Q. Mr. Olson, let's assume we have taken a core from the sand that is 100 per cent water wet or 100 per cent water saturated. Will you state what the interstitial water factor would be? A. That would be 100 per cent in that case.

Q. Would the irreducible water factor be the same? A. No. The way the irreducible water is determined, it would not.

Q. Mr. Olson, at transcript 1814, you mentioned that the reservoir pressures in the Rayne field are abnormally high. Do you have that reference? A. One moment, please.

Q. I believe it is at lines 22 and 23.

2451

A. I have it now, yes, sir.

Q. That isn't true for all the reservoirs, is it, Mr. Olson, in this field? A. It is true for all of the reservoirs with the exception of the Klumpp A. sand.

Q. Would you say that that Klumpp A. sand has a normal pressure gradient? A. I would say that it is possibly approaching the normal pressure gradient, yes.

Q. Thank you.

Will you please refer to your map exhibits or the maps in your Exhibit X-2? Do you have those before you? A. Yes.

Q. Certain lines on those maps are labeled and as I understand purport to indicate the productive limits of the respective sands referred to? A. Yes.

Q. Isn't that correct? A. Yes.

Q. I believe there was some mention made of this yesterday by you, that there is not portrayed or depicted upon these maps certain fault block lines, isn't that correct? A. No. Certain of these lines represent actually the limit of the reservoir due to the fault trace.

2452

Q. Well the thread of the point that I wanted to develop and make clear on the record—and I don't think it should be any particular exercise here.

Let's refer to the tabulation, the first tabulation which is included in your Exhibit X-2. Apparently that is referred to as page 1 of the exhibit. It is not numbered. A. Yes, right.

Q. Now, in that tabulation you have certain column headings with the various sand designations indicated? A. Yes.

Q. I would infer from looking at the exhibit and by reference to those column that you have eight different sands or reservoirs there. Wouldn't that be a natural inference, in the way the exhibit is set up? A. No. I have really—did you say sands or reservoirs?

Mr. Deakins: That is what he said.

Mr. Flaningam: I said sands or reservoirs.

The Witness: Well, just to further make myself clear on it, we are talking about seven different reservoirs in the field, with one of them that we have broken up into two segments.

By Mr. Flaningam:

Q. Isn't it a fact that, for example, the Klumpp D.

2453

sand as well as the Klumpp E. sand as designated on page 1 of Exhibit X-2 reflects data for two reservoirs in each instance, or a total of four reservoirs? Is the question clear? A. No, I don't quite see what you are driving at, Mr. Flaningam.

Q. Well, now—strike that last—you can leave it or strike it if you want to. The question wasn't answered.

Let's refer to the Klumpp D. sand. Isn't it a fact that there is a fault within the limits shown and therefore you really have two reservoirs within your designation here of the Klumpp D. sand? A. As we are considering it in this exhibit, we are assuming one reservoir.

Q. I know, but the fact are—your underlying work papers reveal that there is a fault, and you actually have two reservoirs? A. Would you give me a moment, please, to check my map?

Q. Certainly. A. That is correct. We are considering it of course as one reservoir and it does have two faults, different fault segments in it.

Q. Isn't that also true with respect to the Klumpp E. sand?

2454

A. Yes, it is.

Q: And isn't it true with respect to the Homeseekers E. sand, that you have three reservoirs by reason of these

fault blocks? A. That is correct, yes—three separate fault blocks.

Q. Then if I understand the facts as we have developed them in respect to these reservoirs—for example, in the three reservoirs in the Homeseekers E. sand as you have designated on page 1 of Exhibit X-2, you would have to have at least three wells, I mean one well in each of these reservoirs, to drain the Homeseekers E. sand, for example, isn't that true? A. That is correct.

Q. Then likewise I think it follows you would have to have at least two wells, one in each reservoir, for the two reservoirs in the Klumpp D. sand and the two reservoirs in the Klumpp E. sand? A. That would be the normal procedure the operator would use to drain the reserves from that reservoir, yes.

Q. Thank you.

So your page 1 of Exhibit X-2 you have indicated on line 11 what you have designated as terminal reservoir pressure, have you not? A. Yes.

2455

Q. And I believe in each instance you have shown that or estimated that to be 515 pounds? A. Yes.

Q. Now, it is probably elementary, but I wonder if you would briefly define what you mean by terminal reservoir pressure? A. That is the pressure that is the pressure that we expect the reservoir to be at at abandonment conditions.

Q. Then at that pressure, assumed abandonment pressure for these respective reservoirs involved in this field, you assume that all of the gas reserves which you have estimated in Exhibit X-2 would have been drained? A. That is correct.

Q. And that the reservoirs themselves would actually be drained of all gas in the reservoirs? A. No, they would not be drained of all gas. There would still be a certain

amount of gas remaining in the reservoir at that particular pressure.

Q. You wouldn't expect to be able to produce that remaining gas or gas remaining in the reservoir at your assumed abandonment pressure?

Mr. Deakins: You mean—I object to the question as not clear. You are talking about the gas that would reduce the terminal pressure to below 515 pounds?

2456

Mr. Flaningam: The gas that the witness assumed would be in the reservoir at the time the reservoirs had been produced to the point that the pressures therein would approximate 515 pounds.

Mr. Deakins: O. K.

The Witness: We had not assumed that in this exhibit. However, it could be entirely possible that you might be able to produce some of these reservoirs down to 400 pounds.

By Mr. Flaningam:

Q. In arriving at your estimate of terminal reservoir pressures which you have used in your study, did you consider any water production from the Rayne field sands in determining such pressures? A. We assumed due to the pressures and characteristics of this field that the reserves would be drained by the pressure decline or pressure depletion method.

Q. Would you say that you should qualify that last answer to add thereto the phrase "with the exception of the Klumpp A. sand," which you have earlier indicated has what we have referred to as a normal pressure? A. The fact that it is a normal pressure does not necessarily mean that it also can't be or will not produce down as the pressure depletion type reservior.

Q. Well, is the answer to my question "Yes" or

2457

"No"? A. I included—for my statement, I have included my entire reserve basis.

2458

Q. You said, Mr. Olson, as I understand it, that because of the abnormally high pressure in the reservoirs other than the one sand we mentioned, that you will have pressure depletion in these reservoirs, did you not? A. That is correct, yes, sir.

Q. Well if I understand your testimony in regard to the abnormal pressures in the certain sands and the normal pressure in the other, then you really don't know whether it will be pressure drive or water drive in these reservoirs? A. To mak my answer a little more clear on this subject, I might say that for the experience and what we have observed with reservoirs in south Louisiana, as to our abnormally pressured, that in the cases that can be observed at the present time that have had a certain amount of production taken out of them, that the pressure depletion method is what you would normally expect. I can't say definitely that the Klumpp A will react in the same way. There is nothing that is going to tell me at this moment to say that it will not or that it won't—it will or will not act the same way. I can't say because we have no history on the reservoir. It is entirely possible it might have some water drive in connection with the pressure drop.

Q. May I refer you to your testimony on transcript page 2319, lines 4 through 7. That is yesterday's transcript.

2459

A. I have it here, yes, sir.

Q. You have indicated there, have you not, that there are only two reservoir drive mechanisms, have you not,

namely water drive and pressure depletion? A. Yes. I could have further expanded on that answer by saying you could have the combination of both.

Q. Mr. Olson, let me ask you again, did you consider any water production from the Rayne field sands in determining your terminal reservoir pressures? A. No. We assumed that there would be no major water encroachment in this field at the time we made our estimate.

Q. Wouldn't it be a fact that water production could have a great effect on the terminal reservoir pressure? A. If you are taking a theoretical case now, it is entirely possible. Certainly it would have an effect on terminal pressure.

Q. Now, let's take an actual case, the Rayne field itself. Don't you have data definitely indicating that water will be produced from wells in the Rayne field? For example, and in that connection, I call your attention to the fact that the Nodasaria A sand, Unit 9 well has a scheduled work-over to squeeze and recomplete higher the shut-off water production? A. That is correct. I am familiar with that well,

2460

and as I expressed myself this morning, undoubtedly in that area is some formation water that is being produced out of that well. We are not positive why that is happening. We are assuming that it might be some local condition or else a break in the tubing or a poor cement job or some factor of that nature.

We realize that in this particular well this is happening, but on an overall basis for the field we do not expect it.

Q. The fact that you are proposing to recomplete at a higher elevation suggests, does it not, that the water encroachment is coming in from below? A. The reasons that the well is to be work-over I believe you find a better

answer that Mr. Marshall can give, for his reasons behind working that well over.

Q. Well, we will toss that one to Brother Marshall.

Isn't it a fact that the Edward Arceneaux well, No. 1, completed in the Homeseekers E sand, produced on test May 10, 1961, approximately 470 barrels of water A. Subject to check on that amount of water, I will accept your answer as being correct there.

Mr. Deakins: I move to strike the answer, of Mr. Olson. There is no evidence of this. I have had this subject check business pulled on me in 18968, Mr. Examiner, and made up my mind it would be the last time.

2461

Mr. Flaningam: Well, your witness proposes it. I didn't ask him to take it that way.

Mr. Deakins: That is why I move to strike the answer.

Presiding Examiner: Mr. Flaningam, I think the staff asked this witness this morning in your absence a question involving the amount of water produced from the well which you mentioned during the month of May, 1960.

Mr. Flaningam: 1960?

Presiding Examiner: Yes, sir.

Mr. Flaningam: The date I have here is May 1961.

Presiding Examiner: Well—

Mr. Lewnes: I believe, Your Honor, we also gave them the 1961 date, but we asked that he relate it to the volumes of gas—

Presiding Examiner: I am going to get to that in a minute.

Mr. Lewnes: I am sorry.

Mr. Flaningam: I am sorry, sir.

Presiding Examiner: In May 1960, staff asked the witness to check his work papers and ascertain whether or not 4,950 barrels of water was produced from that well during the month of May, 1960.

They further asked him to check and determine whether or not during the month of May, 1961, 14,632 barrels of water was produced from that well.

2462

Mr. Deakins: Mr. Examiner, I think you have the wrong wells.

I think you are talking about the southeast fault block of Unit 1 of Homeseekers E.

Presiding Examiner: I am.

Mr. Deakins: Well, didn't Mr. Flaningam—

Presiding Examiner: Isn't that the one you inquired about?

Mr. Flaningam: I am talking about the Edward Arceneaux in the Homeseekers E sand.

Mr. Deakins: Unit 2?

Mr. Flaningam: No, this is No. 1.

I didn't mean, Your Honor, to certainly reproduce some ground that we have been over.

Presiding Examiner: You haven't been here this morning. But staff went down through this morning, and asked about—let me say—

Mr. Flaningam: My associate certainly doesn't consider that we are going over what was covered this morning. At least we are certainly trying to avoid it.

Presiding Examiner: Staff asked about 22 wells this morning, and the water produced from those 22 wells in May 1960 and May 1961. And they were two wells that had a high water production. You inquired about the first one, and I thought the second one that you inquired about was the other one.

2463

The Witness agreed to check his work papers and report back on staff's questions about the water production.

Mr. Flaningam: I think I will defer that until he reports

back. And I will have had an opportunity to check the transcript of this morning's.

Presiding Examiner: You can look at the record and then you will be familiar with what was reported.

Mr. Flaningam: Yes, sir.

Mr. Deakins: I thought it was different. That is why I couldn't relate it to anything we had today.

Mr. Flaningam: I am going to pass up any further questions on this subject on the assumption the witness is going to return no sooner than tomorrow sometime, and we will have had a chance to check the record.

Presiding Examiner. He may clarify then what you intend to ask him about now.

By Mr. Flaningam:

Q. Will you refer to your Exhibit X-2, to the first map, and state whether or not the Quebodeaux Well No. 1 in Section 7, Range 3, Township 9 south, is completed in the Krumpp A sand? A. That is the present completion, yes, sir.

Q. What is the approximate distance from that well to the farthest productive portion of the Klumpp A sand? Would you say it is approximately 10,000 feet?

2464

A. Yes, I would say that was a pretty good approximation.

Q. Do you consider that that well will efficiently drain the Klumpp A sand, Mr. Olson? A. No. I believe it will certainly be necessary to put other wells into that sand.

Q. Now, will you refer to transcript page 1813, Mr. Olson? You testify there, do you not, including two additional reservoirs in your Exhibit X-2 as compared to your earlier studies of this field? A. That is correct.

Q. Are you familiar with the fact that Mr. Jacobs at transcript page 1898, at lines 2 through 9, relied upon

the testimony that you gave at transcript page 1813 apparently, and stated as follows: "While it is, of course, not exact as to what will be the future history of this field there is also the definite possibility of future discoveries and production history which increase the gas reserves and at the same time decrease the net cost per Mcf of gas produced in Rayne field."

He further stated: "This has been indicated in the testimony of Mr. Olson in connection with the new Homeseekers D-1 and D-4"—I am sorry. A. D-2.

Q. "Homeseekers D-2 and D-4 sands." Then he goes

2465

ahead and says "And, of course, there may be others."

You are familiar with that testimony of Mr. Jacobs.

Mr. Deakins: You mean Mr. Olson? "Of Mr. Jacobs," did you say?

(Laughter.)

The Witness: I believe I was in the room at that time.

Mr. Flaningam: I think the reporter has it straight for the record, Mr. Deakins.

By Mr. Flaningam:

Q. One of these—this Homeseekers D-4 sand I think we already touched upon.

Q. You consider that as not having been tested. We won't pursue that any further.

Isn't it a fact that a number of other sands in the Rayne field, other than the sands for which you have included estimated gas reserves in Exhibit X-2, have been tested and found unproductive. A. I can't remember exactly what sands they might be. It was in my opinion that there were some other sands that I believe might possibly contain gas and will be brought in on production

when some of these other reservoirs are possibly depleted. It is just an opinion that I have.

Q. You didn't apparently think so well of your opinion that you included any reserves in your Exhibit X-2 for those particular sands or reservoirs?

2466

A. No. It was just an approximation on my part that I feel that some time in the future that some of these other sands might possibly produce gas.

* * * * * * * * * *

2469

Dan L. Marshall

was recalled as a witness and, having been previously duly sworn, was examined and testified further as follows:

Presiding Examiner: Your witness, Mr. Lewnes.

Cross-Examination

By Mr. Lewnes:

2470

Q. Mr. Marshall, will you refer to page 2 of Exhibit X-2? A. I have it now.

Q. Right. Mr. Marshall, when I make a comparison of the condensate and the plant liquids to be prodced in what is shown there as the first year and the second year, it appears that more condensate and more plant liquid is to be produced in the second year, 1962, than what is scheduled to be produced in 1961. Yet, the amount of gas to be produced for each one of these years is the same.

Now, could you indicate how that results? A. In the year 1962 the production from the Nodasaria sand as well as from the Homeseekers E sand was increased and the Nodasaria, being a richer reservoir, I mean having a higher liquid yield, and producing more gas, results in the production of more liquids in that year than in 1961.

Q. Well, now, you say the produtcion from these wells was increased from that reservoir. These are actual production figures. A. These are anticipated, estimated future rates of production. I think that shows on the exhibit.

Q. Oh, in other words, then, this is predicated on your assumption that the volumes, the 51,100 MMcf to be produced in the year 1962 will be taken from those particular

reservoirs? A. That is correct.

Q. Mr. Marshall, you also stated—I believe you said some reservoirs are richer than others? A. That is right.

Q. Could you elaborate a little on that? A. The condensate yields in the various reservoirs do vary from reservoir to reservior.

Now, the ultimate condensate yields as related to the residue gas as shown on the first page of Exhibit X-2 reflect those difference in ultimate condensate yield.

Q. Now, if I understand what you said up until this moment now is that the condensate and plant liquids to be derived from the volume of gas to be produced may vary, it all being dependent upon which reservoirs you are meeting the annual volume from, is that correct? A. That is correct.

Q. Now, in order to arrive, then, at your condensate and plant liquids, what did you use as a basis for determining that the annual volume would be produced from the various reservoirs or from the specific reservoirs upon which you would get this condensate and this plant liquid? A. These rates were generally in accord with current allowable rates at least as to the year 1961.

Beginning in 1962 and for a period until 1968, with-

2472

drawals from the Klumpp A and Klumpp D reservoirs were restricted to a half million cubic feet per day per well.

The balance—or an adjustment then was made in an upward direction on the gas to be produced from the Homeseekers E sand, the Nodasaria north and south. The withdrawals from these reservoirs were roughly in proportion to their reserves. That is, the relative withdrawals from the three.

Q. Then are we to assume that after 1968 they may not necessarily be in proportion to their reserves. A. After—no. They were—

Q. Oh. A. Throughout the life of those three principal reservoirs, the rates of production were roughly in accord with their reserves so long as there was delivery capacity available to produce that amount.

Q. Now, as to the remaining wells. A. The remaining sands?

Q. Sands. A. They are being—or it is anticipated that these will be produced in this schedule roughly at current allowable rates, until they no longer have the capacity to deliver at those rates.

* * * * * * * * * *

2481

Q. Now, how did you arrive at the ratio of condensate and plant liquids that would be derived from the scheduled volumes of gas indicated on page 2 of Exhibit X-2? A. I believe in my direct testimony, Mr. Lewnes, I said that in the case of certain reservoirs there were available laboratory studies of the volumetric and phase behavior of the hydrocarbon mixtures in those reservoirs.

Where such data were available, they were used to estimate the volumes of condensate and plant liquids that would come out—that would be produced at varying pres-

sures during the depletion of these reservoirs. For those reservoirs for which laboratory data of this type were not available, correlations were made as between the data that were available, and these correlations used to produce similar estimates for the reservoirs for which the laboratory studies were not available.

Q. Which reservoirs did you have laboratory data available? A. They were available on the Klumpp A., Homeseekers E.,

2482

Nodasaria A. north, and Nodasaria A south reservoirs.

Q. Now in arriving at these ratios, did you not take into consideration the actual production figures of condensate and plant liquids in relation to the volumes that had been produced? A. I attempted to do so.

Q. Now, Mr. Marshall, isn't it a fact that if you look at the ratio of your plant liquids on page 2 of Exhibit X-2 as it relates to the volume of gas to be produced and make that same comparison with the volumes produced and the plant liquids produced as indicated on Exhibit X-20, that will show that the plant products, the plant liquids have been produced at a greater ratio than that which you indicate in your Exhibit X-2? A. Do you mean by that, Mr. Lewnes, that the yield of plant products per unit of gas processed is higher on Exhibit X-20 than on X-2?

Q. That is correct. A. I have not had an opportunity to make such a comparison from Exhibit X-20.

I can relate to you what comparison I did make.

We had available to us at the time this work was done the results of the first twelve months of operation of the Rayne gas processing plant.

We took the volume of production as it came, gas

2483

production as it came from the various reservoirs, and applied our anticipated yields of plant liquids to it and

found that it was some 7 per cent lower than what was actually produced.

So with that, we then applied a correction of 7 per cent to our calculator yields in an upward direction.

I think that the data—I am positive that the data that we used to make this comparison is a matter of public record in the files of the Department of Conservation in Louisiana. And whether or not it is the same as is shown on Exhibit X-20 I do not know.

Mr. Flaningam: Would you state what period was covered? I mean you said the first twelve months?

The Witness: Well the plant began operations, Mr. Flaningam, in June of 1960.

Mr. Flaningam: That is what I thought Exhibit X-20 indicated. I just wanted to be sure.

By Mr. Lewnes:

Q. Mr. Marshall, when you made this comparison I think you referred to the production in the first year of Rayne field. Did you make that comparison with residue gas or total field production? A. No. This comparison was made with the total field production. It is a matter of coincidence that it was done that way. It happened to be convenient so to do.

2484

Q. Well, in other words, in order to find out what your ratio, then, is, you take the total plant liquids, divide into total production, and come up with a ratio as to what your ratio is for plant liquids in relation to volume of gas produced; is that correct? A. As you described it and defined it, it is obviously the ratio between the plant products and total field production.

Q. And you don't have a ratio that you could give us right now as to what it is in relation to your Exhibit X-2? In other words, do you have a figure as to what that ratio

is reflected in the volumes shown on Exhibit X-2? A. I do not have a single figure, no, sir.

Q. In other words, in order to come up with the volumes you have shown on plant liquids, is it not a fact that you would have to go reservoir by reservoir and state that so much gas is going to be produced from each one of these reservoirs in order to get the plant liquids which you have indicated in your Exhibit X-2? A. I would.

* * * * * * * * * *

2505

Thursday, December 7, 1961.

* * * * * * * * * *

2506

Stewart P. Osborn

resumed the witness stand and, having been previously duly

2507

sworn, was examined and testified further as follows:

Presiding Examiner: You have been sworn previously, Mr. Osborn, haven't you?

The Witness: Yes.

Presiding Examiner: Are you ready, Mr. Lewnes?

Mr. Lewnes: Yes, sir, Your Honor.

Cross Examination

By Mr. Lewnes:

* * * * * * * * * *

2542

Q. Now referring to transcript page 1945, where again, at line 5, I posed a question to you—wait. I am sorry. This was during your direct testimony. The question was, "Do you believe Texas Eastern is entitled to earn a reasonable rate of return on its investment in the Rayne field?"

And your answer was "Yes", and you gave an explanation.

Now, would you define what you meant by investment, or what your answer pertained to as it relates to the word "investment"? A. Well, I believe that the investment should include all items of cost which we would have in the Rayne field.

Q. Well, could you start indicating what costs you are referring to? A. Well, I am referring to what we will have invested in our plant in the Rayne field. Does that answer it?

Q. Is that your entire answer? A. Yes, sir.

Mr. Lewnes: Will the Examiner direct the recorder to have

2543

the answer read back, please.

Presiding Examiner: Will you read the witness' answer, please, Mr. Reporter?

(Answer read.)

By Mr. Lewnes:

Q. Is your investment in your plant—your use of the term—synonymous with what you have shown on Exhibit X-10? A. No, it is not limited to that, Mr. Lewnes, no, sir.

Q. Well, what other items should we include? A. Well, it is rather hard for me to answer right now because I haven't prepared a study for a rate presentation. But I would say this to you, that—and I can't speak for management, but we certainly would have to give some consideration to our balances in our excess note payments.

Q. You are referring now to what is reflected on Exhibit X-8? A. Yes. Just a minute, I have to check that. Yes, sir.

Q. Well, for rate of return purposes you have indicated you would include certain items.

Would you or would you not include your miscellaneous deferred debits accounts for rate of return purposes?

2544

Mr. Deakins: Mr. Lewnes, let me—I don't know whether I want to object here or not. I was wondering whether you were asking him what he thought ought to be done or speaking for management.

Mr. Lewnes: I believe he is the comptroller and the comptroller I believe makes up the figures here, what goes in and what does not go in.

Now, does he include it in or doesn't he, or if he wants to state that he has to wait until someone advises him in Texas Eastern as to whether he will or won't—he can answer any way he likes.

Mr. Deakins: Mr. Examiner, I object to the question. It is repetitious. That question was answered previously. He said he wasn't prepared to speculate at this time as to what the return should be.

Mr. Flaningam: Your Honor, as a matter of clarification: When staff counsel refers to miscellaneous debits, is that something different or is he intending to refer to this other deferred debits account? A. It is just a matter of getting clear on the record what we are talking about.

Mr. Lewnes: What appears on Exhibit X-8, which says Rayne field, Schedule of activities in the other deferred debits account. That is the old title as appearing in the uniform system of accounts. The account now reads miscellaneous deferred debits account.

2545

Mr. Flaningam: So we are referring to the same thing.

Mr. Lewnes: That is correct.

Mr. Flaningam: I think that is very helpful.

Mr. Deakins: Mr. Examiner, in connection with that objection, let me read a statement that the staff of this Commission made in this very same case in the United States Court of Appeals for the District of Columbia Circuit in its brief at page 21.

Mr. Lewnes: Excuse me—

Mr. Deakins: Here is the position they took at that time.

Now, I am quoting: "The entry of certain figures in Taxas Eastern's books of account does not control the Commission as to the ultimate accounting to be followed, and in any event does not control the disposition of any future rate case. The Commission order here fixed none of Texas Eastern's rates to its customers."

And that is what they said.

Mr. Lewnes: Precisely, Mr. Examiner. That is why we are back here.

Mr. Deakins: That is right.

And now they want to confine him to something which the witness has said can't be done.

Presiding Examiner: Well, the witness said this. He said he was the comptroller. He said he might make recom-

2546

mendations to the Texas Eastern executive committee and what they did with it he didn't know.

Now, he can't testify for management. He can testify what he knows of his own knowledge, and not for management.

Now limited to that, the witness may answer.

The Witness: May I have the question, please, Mr. Examiner?

Presiding Examiner: Will you find it and read it, Mr. Reporter?

(Question read.)

(2546)

The Witness: Well, I certainly ~~would take~~ that balance into consideration in anything that I would be doing, Mr. Lewnes.

By Mr. Lewnes:

Q. Well, again, I don't think you have answered the question. As an accountant, do you consider miscellaneous deferred debits account as part of investment, of this nature now? Do you consider that as part of investment or don't you? A. I would say as an accountant I would, yes, sir.

* * * * * * * * * *

2581

E. A. Olson

was recalled as a witness and, having been previously duly sworn, was examined and testified further as follows:

Cross-Examination (Cont'd)

Mr. Deakins: You want us to put this information in you requested yesterday? We are ready to do it now before you start cross, if you want to.

Mr. Lewnes: Yes. That is O. K. You can put it in—

Mr. Deakins: It is up to you. I would just as soon do it one time as the other.

Mr. Lewnes: Yes.

By Mr. Deakins:

Q. Mr. Olson, yesterday Mr. Lewnes furnished you certain data regarding water occurring in the well formations and ask you to check that against the total production of gas, as I understood it, to come up with a percentage, is that correct? A. Yes. I have made the required calculations of the water data supplied by the staff and put into the record.

However, I was unable to check the barrels of water in a number of instances with the data that I had available to

2582

me.

Now, unless the staff was furnished with some additional data that I may have no knowledge of, that could explain these discrepancies.

I wish to state, however, that two wells in the Rayne field, namely the Nodasaria Unit 9 and the Homeseekers E southeast fault block Unit 1 well are both making formation water, but that all of the other wells that are making water, as I have previously testified to, are making a small amount of water vapor that condenses out of the gases of this nature as the gas is produced at the wellhead.

Q. All right.

Now, did you make the calculation that I asked you to do? A. Yes, sir, I have.

Q. All right. Would you just state that for the record, unit by unit? And I think it is year by year, isn't that correct? That would be for the years 1960 and 1961 separately, commencing with Nodasaria Unit No. 1 through 9, and then follow the same the same outline as Mr. Lewnes used in his cross-examination of you. A. If the staff requires it, I have made the barrels of water per million figure—if that is what they have in mind now.

As I say, these figures came from the water that the

2583

staff put into the record, of which I am not sure of how accurate they are.

Q. Yes. A: If they still so desire me to read off these barrels per million—barrels of water per million cubic feet of gas here, why I will be glad to, by wells and by May 1960 and by May 1961.

Q. You mean by that you only made the calculation. You couldn't check all these, is that correct, as to accuracy?

A. As I stated, there were a number of water figures, monthly water figures that the staff put into the record with the data I had available I could not check.

Mr. Deakins: You want him to go ahead and read those?

Mr. Lewnes: Yes.

I would like to indicate that all the water figures that we submitted into the record were taken off work papers submitted to us by Texas Eastern and it would appear, then, that this witness did not have available to him some of the work papers that were submitted to us by Texas Eastern. That is about the only reason I can find why you couldn't check these figures. And if you so desire, I can give you the work papers that we had.

Mr. Deakins: Let's have him look at it.

The Witness: Could I have it, please?

2584

Mr. Deakins: Did you have those?

The Witness: No, I did not have these figures. So you had something in addition to what I had.

What I was attempting to do was to just check on a daily test that was made in the DT-1 records that are submitted to the Louisiana Department of Conservation.

So with this, I will accept these as being authentic, as long as these were submitted to you by Texas Eastern.

Mr. Deakins: All right, then, go ahead and read your calculation.

The Witness: The way I will read these will be the well number, the sand and well number, and then the barrels of water per MMcf for the month of May 1960, and then for the month of May 1961. Is that—

Mr. Lewnes: You are going to give us the ratio, are you not?

The Witness: Yes, the barrels of water per million.

Mr. Lewnes: O. K.

The Witness: If you so desire this information. Nodasaria Unit 1, 1.5.

By Mr. Deakins:

Q. That is for 1960, May 1960, is that right? A. Now, instead of my repeating May of this and May of that—

Q. All right. A. I will just include two figures for each one. The

2585

first one will represent May 1960 and the next will represent May 1961.

Q. O. K. A. Nodasaria Unit 1, 1.5 and 1.4.

Nodasaria Unit 2, 1.2 and 1.9.

Nodasaria Unit 3, 1.2 and 1.8.

Nodasaria Unit 4, 1.5 and 1.6.

Nodasaria Unit 5, 1.6 and 2.2.

Nodasaria Unit 6, 1.2 and 1.7.

Nodasaria Unit 7, 2.1 and 1.7.

Nodasaria Unit 8, 1.4 and 2.5.

Nodasaria Unit 9, 28 and 36.8.

Homeseekers D-2 Unit 2: I have nothing for May of 1960. In May of 1961, 1.8.

Homeseekers E Unit 1, 2.6 and 2.2.

Unit 2, 1.5 and 9.

Unit 3, 1.5 and 4.2.

Unitd 4, 1.3 and 1.7.

Northeast Fault Block Unit 1: Nothing in May of 1960 and in May of 1961, 5.3.

Homeseekers E Southeast Fault Block Unitd 1, 5 and 203.

Klumpp A, Quebodeaux No. 1: I have nothing for May of 1960 and 2 for May '61.

Q. Did you leave out the South Fault Block—the Marie Petitjean?

2586

A. The Marie Petitjean is not considered a well in part of this field as a reserve estimate. That is why I left it out. Klumpp D, the Arceneaux Unit 2, 1.2 and 2.

Elton Arceneaux Unit 1, 1.1 and 1.3.

W. Petitjean Unit 1, 2.7 and .76.

W. Petitjean Unit 4, nothing in May of '60 and 52 in '61.

Q. That concludes that summary, does it not? A. Yes, sir.

Mr. Deakins: I think that is all we have, Your Honor.

* * * * * * * * * *

By Mr. Flaningam:

Q. Isn't it a fact, Mr. Olson, that the Nodasaria A sand Unit No. 9, Well No. 1, mentioned on transcript page 1824 as a proposed work-over, produced in May 1961, 3,000 barrels of salt water? A. Yes, that is the figure I have here on my paper.

Q. Then, isn't it also a fact that the Homeseekers E Unit 1, in the Southeast Fault Block, that is the E. Arceneaux No. 1 well, produced 14,832 barrels of salt water in May 1961?

2587

A. That is the figure I have on my paper.

* * * * * * * * * *

2589

Redirect Examination

By Mr. Deakins:

Q. Mr. Olson, yesterday Mr. Lewnes read into the record what was claimed to be the differences in net pay that you used compared to those which appear on some sort of a Continental Oil report which are not in this record.

Let me ask you this: When you made your study of this field did you have that information available?

2590

A. I had copies of this particular form that Mr. Lewnes referred to, yes, sir.

Q. Did you rely on that in any way? A. I rely on these forms. They are called new well completion and abandonment record forms. We rely on these forms to obtain several things—the completion of the well, the location of the well, drill stem tests that may be indicated, and physical equipment contained in the well, and possibly some other minor items.

Q. But how about with reference to the estimate of net pay thickness? Do you rely on that or do you make an independent study? A. No, we don't even bother to check that particular data, as we are only interested our own self in making our own independent study and whatever anybody else has done on a form of this nature we would not put any qualifying statement at all on it.

Q. Why is that? Is that because you don't know what information they have available or— A. I have no idea of course, who counted the sand, how it was counted, or what type of information was used to obtain it, and without knowledge, of course, who might have done something and their particular qualifiaction one could not put any particular significance to it.

Q. Now, yesterday Mr. Flaningam asked you some question

2591

with reference to the drill stem test on the Navarro A-1 well in Homeseekers D-4 sand.

Let me ask you—you said at that time that you didn't know what the interval was. Have you since that time checked the interval, and if you have, state what you found. A. Yes. I would like to just clarify for the record—into this test that Mr. Flaningam told me about,

the Navarro No. 1 well, pertaining to the Homeseekers D-4 sand.

The particular interval that I show on the new well completion form was from 12,382 to 12,440.

Q. Feet? A. Feet.

Q. Right. A. The remarks opposite this particular test indicated salt water and gas. And I believe it was stated that it is just made salt water. So I want to clarify that particular part.

Now, the main thing that I want to bring out here in this test is that the proved limit that we have used on the Homeseekers D-4 reservoir was at 12,286 feet. So that this particular interval that I have previously mentioned is below our proved limit that we have used for the reservoir.

We have not included any net gas pay in the Navarro well for this particular sand.

Q. Well, is it likely that there is some?

2592

A. We, of course, did not conclude that this was a conclusive test in this reservoir, mainly because of the fact that we did not have the backup data to go with the remarks of salt water and gas.

Now, you can draw some conclusion, however, and that is that some gas was undoubtedly made. So in that respect I would say it does strengthen the fact that we have included this reservoir in our estimate.

Q. Now, yesterday in response to some question of the staff which started out in connection with a 93 percent recovery factor, I think Mr. Lewnes asked you if you knew of any wells that had been produced at abandonment pressure of approximately 500 pounds or—

Mr. Lewnes: I object, Your Honor. I don't think we have asked him that question.

Will counsel please specify where in the transcript we

did ask that question, as to the wells that had been produced at that particular—

Mr. Deakins: Well, let me ask you this—on redirect, I will ask you this question.

By Mr. Deakins:

Q. You are familiar with the fact that yesterday Mr. Lewnes asked you whether or not you had ever made an estimate of reserves which showed a recovery factor of 93 percent, isn't that correct?

2593

Mr. Lewnes: We object again. Your Honor, that is not the question we posed to the witness. The question posed to the witness was: In any proceeding in which he prepared exhibits to be filed with this Commission, did he include a recovery factor as high as 93 percent, other than for any application that might have been filed on behalf of Texas Eastern. That was the exact question posed to the witness.

Mr. Deakins: All right. With that correction—

By Mr. Deakins:

Q. You recall that question, don't you? That question was asked you? Just answer yes or no. A. Yes, I recall that question.

Q. All right. Now, I think you testified yesterday also, and correct me if I am incorrect in this, that you did not use a recovery factor in percents, but instead you used an abandonment pressure of 515 pounds per square inch— is that correct? A. In the exhibit I had prepared for this case, yes, sir.

Q. And as Mr. Lewnes calculated it, it apparently turns out to be a 93 percent recovery factor, is that correct?

Mr. Lewnes: We object, Your Honor. We didn't calculate it on the depletion basis. We calculated it on recover-

able reserves as opposed to the reserves in place and came up with this 93 percent factor. We didn't use the abandonment

2594

pressure calculations.

Presiding Examiner: It seems to me in the beginning that staff said they had taken the figure shown on Exhibit X-2, page 1, line 16, which is the estimated initial gas in place and had divided that into the figures shown on line 18 of the same exhibit and column and page and they came up with the 93 percent.

Mr. Deakins: That is right. Well—

Presiding Examiner: And then after that there was conversation between the witness and staff about the abandonment pressure. And then following that, I think the witness testified to an abandonment pressure of a hundred to 515 pounds. And then after that, there was a series of questions by staff of the witness with regard to the Iowa field and any other fields that he migh tknow about that had that high a recovery factor and abandonment pressure.

Mr. Deakins: All right.

Then with that in mind—

By Mr. Deakins:

Q. Now, Mr. Olson, you said yesterday you didn't know of any fields that had abandonment pressure of 515 pounds, as I recall your testimony, is that correct? A. I didn't have any with me, no, sir.

Q. Have you since that time had someone working under your supervision and direction in your office at Dallas check

2595

the records of DeGolyer and McNaughton to determine whether such fields existed? A. Yes, sir.

Q. Who did you talk to there? A. I talked to Mr. E. R. Scott of our firm.

Q. All right. Now, did he make a check in an approximate two-hour period? A. Yes, sir, the check was made.

Q. All right. Will you staate, by number, and state how many fields your records show produced to an abandonment pressure of approximately 500 pounds?

Mr. Lewnes: We object, Your Honor. It is pure hearsay. He is stating what someone told him. He doesn't have—he hasn't made these computations at all. These are things apparently given to him over the telephone by someone else. If we are going to testify along this line, let's bring the somebody else up here and test background of the figures which he used to supply to this witness.

Presiding Examiner: I think the objection is well taken.

Mr. Deakins: Mr. Examiner—

Presiding Examiner: It is pure hearsay.

Mr. Deakins: He testified this was done under his direction. And it is part of the records of his firm there. We put similar testimony in on Docket G-18968.

2596

These are actual fields which are actually producing, at those pounds. It may be very painful to the staff to hear this, but it is a fact, that we have proven in Docket G-18968 by the testimony of Mr. William Gorton as to some of these, and Mr. Olson here—his firm has others. They have made these studies. You know one man in a firm as large as DeGolyer and McNaughton doesn't do all the work.

Presiding Examiner: Oh, I know. I have seen their office out there. I know that one man doesn't do all the work.

Mr. Deakins: That is right.

I only wanted him to name the fields and state the states where they are, so to show that there are other fields. Because that was the question the staff asked him. And he didn't have that at his finger tips. Had he known—had he

had this same thing at his finger tips he could have answered it then and there would have been no objection to it.

Mr. Lewnes: I believe Your Honor has indicated it was not the question we asked the witness. And we have objected to it as being hearsay. I believe the Examiner has passed on it.

The Witness: It seems—

Mr. Deakins: Wait a minute, Mr. Olson.

Presiding Examiner: It is Rayne field we are interested in. How many other fields have abandonment pressures at that 500 pound I don't think makes any great material difference.

2597

The objection is sustained.

Mr. Deakins: I didn't think it did, either, Mr. Examiner, except it appeared that there was an effort to impugn this witness by the fact that he had only made this one estimate before this Commission.

* * * * * * * * * *

2641

Thursday, November 29, 1962

* * * * * * * * * *

2642

Chairman Swidler: Pursuant to the Commission's order issued October 24, 1962, oral argument is now to be heard on the issues raised by the exceptions to the examiner's decision in the reopened proceedings in Texas Eastern Transmission Corporation, et al., Docket Nos. G-12446, et al.

* * * * * * * * * *

2643

Oral Argument of Jack D. Head

Mr. Head: My name is Jack D. Head, representing Texas Eastern Transmission Corporation. I would like to reserve 15 minutes of my time for rebuttal.

Chairman Swidler: Very well.

* * * * * * * * * * *

2653

After the issuance of this opinion, Texas Eastern, on July 27, 1959, acquired the Rayne field leases, connected them to its system in August of 1959, and the gas has been flowing through Texas Eastern's system to its customers since that date.

* * * * * * * * * * *

2658

Commissioner Ross: Is there anything to prevent you from making sales from this Rayne field to another pipeline?

Mr. Head: No, sir. Not under my conception of the law. However, I can't conceive that we would do it. We have already built into the Rayne field. It is already connected into our system. I do not believe—

Commissioner Ross: You say you haven't dedicated it to anybody specifically, so theoretically then you have the right

2659

to make sales to another pipeline that would offer you a good price for it?

Mr. Head: As I appreciate the law today, sir, I don't believe that leases owned by a pipeline, are dedicated to the pipeline, going back to the Panhandle Eastern case—I will tell you this, Texas Eastern would not even consider

it. You asked me, as a legal proposition, could we? I think it is possible.

* * * * * * * * * *

2670

Commissioner Ross: Why should they agree to it? They aren't being furnished this gas. You aren't dedicating it to them, are you?

Mr. Head: We are not dedicating it to them, no, but it is gas available to our system which they at that time thought we should have.

Commissioner Ross: You thought you were going to sell it to them, then, until you changed your mind?

Mr. Head: I never changed my mind, sir. I have been selling gas from this field to the customers as a part of my rolled-in supply since August of 1959.

Commissioner O'Connor: You have a commitment to the

2671

customers for a volume of gas. It doesn't necessarily have to come from Rayne?

Mr. Head: No.

Mr. O'Connor: The reserves from the Rayne Field support that commitment?

Mr. Head: The reserves from the Rayne Field support that commitment, and certainly, as I say, as a practical matter, Texas Eastern would never sell the Rayne Field gas to anybody else.

* * * * * * * * * *

2674

Commissioner Ross: Do you actually own the gas under the Louisiana law?

Mr. Head: Under Louisiana law, and I am not a Louisiana lawyer, you do not own the minerals in place, but when you have a lease, you own the right to explore for

and produce those minerals and to continue to produce them so long as commercial production is maintained.

Under the laws of Texas, you actually own the gas. Under the laws of Louisiana, you only own the right to produce it.

Commissioner O'Connor: Under a similar contract in Texas, you would own the gas?

Mr. Head: No, under Texas, the mineral owner is still going to own the gas. But under Louisiana, you can't own the minerals, for more than 10 years, and they have a restriction there. At any rate, we do not own the gas, we own the right

2675

to produce it.

* * * * * * * * * *

2676

Oral Argument of Mrs. Barbara M. Suchow

Mrs. Suchow: May it please the Commission, my name is Barbara Suchow. I am Assistant Counsel of the Public Service Commission of New York.

* * * * * * * * * *

2683

Before my time expires, Your Honors, I would like to mention one point, relating to an issue which PSC has never raised in this proceeding, but which has become important in the case since the remand. We are very eager that PSC's failure to file exceptions to the Examiner's decision should not be construed as concurrence or acquiescence on our part in his ruling on the jurisdiction over the sellers issue. We don't agree with him at all. We agree with the posi-

2684

tion asserted by the staff, by Examiner Weston in his interim decision of last January in the MCN case, by other

intervenors, and in other cases, and by the staff in Tennessee's Bastian Bay case, CI61-106, I believe.

Our reason for not filing exceptions to the Examiner's decision on that issue is that we didn't feel aggrieved by it. Rather, we feel that the operative provisions of his decision vindicates completely the basic objective of PSC in this case from the beginning, and that is: It demonstrates that the consuming public can be adequately protected through the Commission's jurisdiction over the pipeline, even if the Commission should choose not to—or should choose to defer decision on the jurisdictional issue in this case.

* * * * * * * * * * *

2685

Oral Argument of J. David Mann

Mr. Mann: Mr. Chairman, members of the Commission; my name is J. David Mann, and I appear here both for the United Gas Improvement Company and for the Philadelphia Electric Company, which I shall refer to simply as the Philadelphia Companies, and I should appreciate it if I may continue my argument for the total of 25 minutes allowed. Hopefully, I can give back five minutes you gave my good friend, Mr. Head.

* * * * * * * * * * *

2687

As I will say to you subsequently, we do not insist you assert this jurisdiction. Indeed, we suggest that you do not have to. But I urge you most earnestly to reject the Examiner's conclusion that you lack the jurisdiction, for if you do not, in

2688

my judgment, indicate your belief that you have jurisdiction over this kind of transaction, it seems to me that you

will have opened a very great loophole in the entire regulatory structure over procedures. You will have created, if you will, by silence or inaction, the very kind of regulatory gap which the Phillips decision, the CATCO case, and others, have suggested must be closed.

Now the producers, by changing the form of their sales contracts, which were originally before Examiner Law of this Commission, have sought to insulate themselves from effective regulation. First, we suggest jurisdictional issues which the record in this case indicates Texas Eastern says has been settled by the Court was not in fact ever before the Court. The brief which was filed by this Commission at page 17 suggests that the Commission had no authority over the lease sale, and that therefore the Court was barred from considering the issue sui sponte.

If that contention is correct, if the Commission at that time, as was consistent with the prevailing philosophy of the Commission at that time, felt that it had no jurisdiction over this kind of a transaction, and it so argued before the Court, query: How could the Court have decided the issue, it was not before it?

I would say that the Court, in commenting on the jurisdictional issue, did say, in passing, that the Panhandle proposition

2689

indicated that the Commission has no jurisdiction over gas leases. This may be true. But I would point out to you that there is a very clear distinction between the Panhandle-Hugoton lease sale involved in the Panhandle case referred to, and this kind of a transaction with which you are confronted today. The Panhandle-Hugoton deal was simply a case in which Panhandle spun off—I forget how many acres of its reserves, or acreage, in the Hugoton field, to the Hugoton Production Company, if I recall it correctly, which was not an interstate pipeline at all. Gas

(2689)

from that acreage never went into interstate commerce. It was never intended to go into interstate commerce.

Contrast, if you will, the Rayne field situation, in which you have crude reserves, everything except the Christmas trees, practically, which reserves were destined to go into interstate commerce, initially under gas sales contracts with Texas Eastern and subsequently under the lease purchase agreement. It seems to me there is a clear line of distinction.

Commissioner Ross: Would you go further and say that were there not this distinction, that the Panhandle case should be overruled, that is in wrong law?

Mr. Mann: No, sir. I wouldn't say that the Panhandle case should be overruled. I think perhaps the Panhandle case is 100% distinguishable from this, and that each can be considered on its own merits. I think that there was probably

2690

some argument before the Commission at one time or another before the Examiner at any rate, that the Commission should not, as a practical matter, assert jurisdiction over this kind of a deal, for the reason that if it did, you would be confronted with a regulatory problem every time Joe Doe wanted to sell ten acres of gas leases to somebody else. This is not the case at all.

In effect, that is what you had in the Hugoton case, the Panhandle-Hugoton case. You would not, in my judgment, by asserting jurisdiction over this kind of a transaction, subject yourself to the kind of administrative chaos it has been suggested might face you if you did assert the jurisdiction.

I would say that the complete answer to this question of your assertion of jurisdiction is found in the Phillips decision itself, which was handled down in June of 1954. The Supreme Court in that case indicated that the Congress

planned to close the regulatory gap at both ends of the transmission lines, and if I may quote a passage or two from that decision, at 347 U.S. 684, the Court said:

"We are satisfied that Congress sought to regulate wholesales of natural gas occurring at both ends of the interstate transmission system."

It seems to me this is clearly that kind of a wholesale, and I urge that the Commission speak out on this point, lest by its silence the Examiner's conclusion that the Commission

2691

lacks jurisdiction may be deemed to have opened the sort of regulatory gap which we believe should not be opened.

Turning now to the question of price:

We have indicated that we do not believe the Commission needs to assert jurisdiction over the transaction to effectively control the situation with which it is confronted here. We have suggested that the answer lies in the Commission's conditioning a certificate issue here by providing that Texas Eastern shall not be permitted at any time in the future to include in its cost of service a price for the Rayne field gas in excess of what you determine to be the in-line price which prevailed at the time of the Rayne field transaction.

Now, that price, it seems to me, is the CATCO price.

Mr. Head argues to you gentlemen, not that the in-line philosophy is not applicable. Indeed, he sought very carefully to distinguish Rayne field from CATCO. He devoted his attention to the fact that even assuming the in-line philosophy applies, Rayne field is a good deal, and that the price involved is an appropriate price.

Now, I am troubled about how to cope with the many numbers Mr. Head used in trying to tell you what this price is. All I can say is, so far as I know, there has been no renegotiation of this contract since the case went to the

(2691)

Court of Appeals. The price which is before you now is exactly the same price which the Court of Appeals had before it when the

2692

cases went up.

The Court of Appeals said, "Under the proposed lease purchase arrangement petitioner claims the total cost to Texas Eastern for each Mcf of Rayne field gas will be 22.89¢, including Louisiana tax of 2.3¢. * * * We think it clear that the price is high enough to be in the disputed area to which the CATCO rule applies."

Now, I do find it difficult to break this price down as Mr. Head did. I can say this to you: that Exhibit X-18 indicates under the title "Texas Eastern Transmission Corporation, Cost of Service Study, Rayne Field, Case 4", that the total cost of gas—average cost—is the 24.34¢ which has been mentioned to you, which includes, if you will, the treatment of the so-called prepayment which Texas Eastern makes because of the fact that it will pay for the gas over 16 years and will take it over a period of 30; again saying, however, I can see no difference in this price from the price that went to the Court of Appeals. As far as I know, it is precisely the same.

* * * * * * * * *

2710

Oral Argument of George P. Lewnes

Mr. Lewnes: My name is George P. Lewnes, Commission Staff Counsel in this proceeding.

* * * * * * * * *

2717

Now before discussing the fluctuating factors, or, as I prefer to call them, the variables, which show that the cost to the consumer for this gas will be upwards of the

94.34¢, we should take a look and see if jurisdiction can be asserted here upon remand, for if it can not, further discussions would be purely academic.

Now staff's answer to the question of whether or not the Commission can raise the jurisdictional question here on remand is a resounding aye, a review of the record made in that Court of Appeals case, as indicated by, I believe it was UGI's counsel, reflects that the jurisdictional or non-jurisdictional aspects of Rayne field acquisition was not challenged in that Court and this was fully acknowledged by Texas Eastern in its initial brief. It therefore follows that although the Court

2718

noted that in the past the Commission was held not to have jurisdiction over gas leases, citing Panhandle, it made no finding as to the jurisdictional status of this specific type of so-called leasehold acquisition. That issue wasn't before the Court. The Court's remark was obiter dictum. It was not responsive to any argument raised in the case. It was completely unnecessary to the decision of the case. And furthermore, as counsel for UGI has pointed out, comparison with the Panhandle case is a vacuous analogy.

All right, what then; what then, were the Commission's enlightening words on this subject when it initially gave the certificate? The Commission stated, in one sentence, "Texas Eastern has not filed an application for a certificate authorizing the acquisition of Rayne field leases and we have no authority to issue such a certificate."

Well, certainly the Commission had no authority to issue such a certificate in view of the fact no application was pending for such a certificate. But as we have said in our brief, even if the Commission had fully examined the facts and terms of the transaction at that time, which it did not, and even if Texas Eastern had made a full and complete

disclosure of its proposals at that time, which it did not, and had the Commission upon a full examination of a complete disclosure specifically found in no uncertain terms that it lacked jurisdiction over this acquisition, it would nevertheless not be precluded from re-evaluating such findings at the present juncture in this case.

2719

The applicants have been unable to cite one lone case in opposition to the myriad of precedent cited by the staff and discussed by the staff in its brief in support of its position, and that is understandable, because there is none. So we move into the next question.

Upon what grounds may we assert jurisdiction in this case? Well, our position has been that once the provisions concerning the subject transaction are denuded of the subtleties of the contractual form the transaction is exposed as being in fact a long-term gas purchase contract subject to the jurisdiction of this Commission. That the Commission has the authority to look behind a contractual form, has been clearly affirmed by the Supreme Court in the P.G. Lake case which we cited, and I quote from the Court's decision there, "These arrangements seem to us transparent devices. Their forms do not controlled. Their essence is determined not by subtleties of draftsmanship but by their total effect."

What, therefore, is proposed to be conveyed? The applicant tells us it is a leasehold acquisition. But their position is akin to the patent medicine man, who after advising the local folks of the curative powers of a particular snake. Assumes a fit of objectivity stating "But don't take my unsupported word for it, folks, read what it says on the label."

Well we have gone beyond the label and analyzed the agreement, and lo and behold, it is the same old gas purchase contract we have been used to seeing all

along, ribband in some novel phraseology.

As they say on the TV commercials, "Make the individual test." Is this a leasehold acquisition or is it a purchase of gas? Here are the facts.

Chairman Swidler: Suppose you concluded that it was a leasehold acquisition, would that be terminated on the jurisdictional question?

Mr. Lewnes: Not necessarily, Your Honor, then we would have to go into a full discussion of the Examiner's rationale, as to why Panhandle is no longer a viable brand of law.

Chairman Swidler: You first distinguish the facts from the leasehold?

Mr. Lewnes: Yes, sir. For ~~an initial~~ down payment of over $12 million and a payment of 16 annual promissory notes totaling over $22 million, Texas Eastern is going to acquire all the seller's working interest gas rights between the surface and a given depth, plus some lease and well equipment and enumerated fixtures. The producer sellers retain all interest in gas, oil and minerals found beyond the gas strata conveyed. They retain or they get all the liquid revenues to be derived during the note-payment period from the gas produced in the strata conveyed.

Additionally, the operator of the interests conveyed will continue to be Continental, who happens to be the largest interest holder here.

Now, in this connection, we note that the installments

are due monthly over a 16-year period. Texas Eastern anticipates producing the gas over a 29-year period, and as previously indicated, there will be prepayments; additionally, the notes have an acceleration clause, so the note

(2721)

payments are geared to specific volumes of productions, causing those installments to trigger or accelerate.

On these facts alone, the instant transaction is akin to situations where the producer and pipeline company enter into requirements contracts to sell and buy gas produced from the field, with the price specified not to so many cents per Mcf, but so many dollars a year. There are various other elements in the instant form of gas purchase contract which have already appeared in the usual producer pipeline gas purchasec ontracts.

There are instances of contracts effective for the life of a field, such as that proposed here. There are also minimum take or pay for clauses in most contracts which require annual dollar payments by the pipeline for up to a given volume of gas, sales in excess of such volume being paid for on a cents per Mcf basis. The minimum dollar amount which the pipeline must pay is usually based on the mutual agreement of the reserves and at what rate they will be produced. We have even seen contracts to sell gas with the cash prepayment feature. That was the recent Wisconsin-Michigan pipeline case. And now a brief look at the law of situs and its relationship to the contracting parties progeny.

2722

Under Louisiana law, and we have cited cases, a leasehold interest is an incorporated interest, a profit a prendre or a licensing to go on the property to search for, to find minerals and sever same and title to the minerals does not vest until they are brought to the surface and reduced to captivity.

Commissioner O'Connor: The same principle applies to the original leasehold then?

Mr. Lewnes: That is correct. What does this mean, then? It means the producers have from the owners a license to hunt for and capture minerals, and that is all

they conveyed to Texas Eastern. Now, in the so-called assignment and conveyance to Texas Eastern, it is not an assignment of a leasehold, but a transference of this license, and in this particular case in part, because the producers have made certain reservations. Whether or not there is specific language contained in the original lease to the producers, permitting them to make a partial transference of their license without the express approval of the owners is not known. Because the leases are not in the record, Texas Eastern having opposed staff's request in the original proceeding to have Texas Eastern submit them into evidence.

Chairman Swidler: The leases to the producers are not in evidence?

Mr. Lewnes: Yes, Your Honor. We do know there is no

2723

privity of contract between the owners and Texas Eastern. One other point on Louisiana law. Under Louisiana law, an original licensee—which in this case is the producer—continues to be liable to the licensor, or the owner, for breaches of express convenant of the lease occurring after his transferal of said license, unless the original license contains a clause expressly excluding him from liability. Again, we don't know whether that is in the leases because we don't have those original leases.

Now we do know, however, or we can infer, that such a clause is not in these leases. Because the producer sellers and the pipeline applicant have entered into a further agreement, whereby in order to save harm to the property for which the producers would be liable to the owners, the producers have agreed to be the operators, that is, Continental, et al., and this agreement will show that it completely vitiates any license given to Texas Eastern under the assignment and conveyance.

What the parties have done here is excogitated magnificant spider webs, being careful apparently to stay within the bounds of Louisiana law, but giving the illusion of having gone beyond the scope of Commission jurisdiction.

The truth of this statement, plus further proof that the parties are in fact contemplating a sale of gas, tile to which will be taken by the purchaser at the surface, may be seen by

reading the assignment and conveyance and in juxtaposition to the management agreement. A management agreement which sets forth that Rayne field will be operated by the producer-seller, Continental, during the note-payment period, an agreement that states that sole discretion as to how Rayne field will be operated and produced is retained by Continental, an agreement that Texas Eastern made no mention of in the original proceeding, an agreement that came to light only during cross-examination of one of the Texas Eastern's witnesses, an agreement that Texas Eastern's counsel arguing here today vociferously opposed putting into the record, and it was only put in the record upon the staff's insistence and the Examiner's direction that it be put in the record.

Chairman Swidler: Did they object to that?

Mr. Lewnes: Yes. The management agreement between Texas Eastern and producers, Continental: It turned out to be the key that let the lid fly off Pandora's box. What is this management? It is a restatement of Continental's duties as an existing operator of Rayne field, plus a commitment that Continental will undertake to be prepared to deliver to Texas Eastern at Texas Eastern's request specified minimum daily quantities of gas during the 16-year note-payments period, and these minimum volumes of gas

are in excess of what Texas Eastern is showing in its rate of production schedule.

Now, Texas Eastern's witness, who negotiated this trans-

2725

action, after much hedging on cross-examination, finally had to be coaxed by the Examiner, and he did admit the manner in which Rayne field will be developed and operated will be at the sole discretion of Continental, as per the management agreement.

Now, the agreement also says that Continental will pay all the enumerated operating costs, but that it will be reimbursed for these outlays. One thus gets the illusion Texas Eastern is paying for the operating costs. However, when we go back to the assignment and conveyance, we find that the reimbursement being made by Texas Eastern to Continental for these operating costs is out of the revenues derived from the liquids produced in conjunction with the gas, revenues that belong 100% to the producer-sellers. In other words, he is paying the producer out of his own pocket. You see, now the producers are actually going to perform in the exact manner as they would under the conventional type of gas purchase contract, but are getting some added fringe benefits which I shall discuss later on. And although now there is some apparent transfer of a license under the so-called assignment and conveyance, Texas Eastern is precluded from exercising any right thereunder by virtue of this agreement.

The agreement also says that the rights and duties of Continental under Article 1 are limited, in that it has no

2726

control over the responsibility for the production from the management area after the production reaches the first control point above the surface on each well. The obligations thereafter accrue to the purchaser, who is responsible for

gathering, handling, et cetera, thus we see the purchaser does not get control or title to the production until it goes past the first control point at the surface.

Now you might say, "Mr. Staff Counsel, what kind of nonsense is this? Why would Texas Eastern obligate itself to pay annual notes over a 16-year period and get title to nothing until, as, if, and when the gas is produced?"

The answer is simple. Texas Eastern is not obligated. There is no direct transaction between Texas Eastern and the producer-sellers. The entire transaction as shown here today is through the dummy corporation, Louisiana Gas, formed by Texas Eastern for this express purpose. Louisiana Gas makes the initial payment to Continental, and will also execute the notes. Louisiana Gas then gets the license. It transfers the license to Texas Eastern simultaneous with Texas Eastern's payment to it of the down-payment which it passes on over to the producer-sellers. Texas Eastern is not involved in the notes. Although Texas Eastern will make the note payments via the conduit, Louisiana Gas, Texas Eastern will not, by express provision, assume or agree to pay the notes. In other words, the producer-sellers have agreed to a no-re-

2727

course action against Texas Eastern, and certainly there are no assets in the dummy corporation, other than $5,000.

2728

However, do not be misled that Texas Eastern's Consumers are thus protected, because although the notes are payable in the 16 years, the production is scheduled for 29 years. Thus, by the end of the note payment period, if production goes according to the way it is scheduled, Texas Eastern will have a balance in its deferred debit account of over 25 million dollars for pre-paid gas, a balance upon which it will seek a return. In the same year, the net investment in facilities is shown to be only $4.

million. If after the note payment, period, the remaining estimated recoverable reserves do not materialize, Texas Eastern's consumers will have virtually bought a pig in a poke.

And this leads us into the question of the reliability of Texas Eastern's reserve estimate.

Commissioner O'Connor: If the reserves are greater than estimated they will incur to the consumers won't they?

Mr. Lewnes: That is correct. However, we will see the reserve estimate is completely overstated, as shown in the record.

But at this point I should just like to make a passing mention of the Panhandle case which has been served up to us as supporting the proposition that the Commission does not have jurisdiction over this type of acquisition. In the first place the Commission does have jurisdiction by virtue of the facts of this case. Secondly, the Panhandle case is a completely different case. And thirdly if necessary the Commission

2729

could go to the Examiner's decision in the MCN case, discussing whether the Panhandle case should no longer be considered precedent. I should like to use the remaining time to discuss the per Mcf price of this gas along with the variable factors affecting the price, a proposed method of resolving the issues and some rebuttal of Texas Eastern's presentation here.

* * * * * * * * * *

2743

Rebuttal Argument of Jack D. Head

* * * * * * * * * *

2745

Now, counsel says that there is something sinister about the management agreement, that he brought that out on

cross-examination of this witness, and then compelled me to bring it forward.

I am sure the Staff Counsel will not dispute my statement that I had theretofore, before the hearing ever commenced, furnished Staff Counsel with the management agreement. He had it. He didn't discover it on cross-examination; it was in his possession. I just opposed the introduction of it because I did not think it was material and relevant to this case, but there was no attempt to hide the management agreement from Staff Counsel. Staff Counsel also complains that he did not have these leases. It is true that in the hearing in which this particular staff counsel did not participate, a request was made for a subpoena duces tecum for all of the lease files, which is a tremendous thing. That was denied by the Presiding Examiner. I can almost swear, I haven't been able to confirm it—but I can almost swear I gave this particular Staff Counsel before this hearing copies of typical

2746

leases in the Rayne Field. He never thereafter requested a subpoena of any other leases or requested of me any additional leases.

Commissioner O'Connor: By typical leases, they would include some?

Mr. Head: They were actually leases which I represented to him were typical of the leases in the field.

Commissioner O'Connor: Including some of Continental's?

Mr. Head: That is right. These were typical leases acquired.

Commissioner O'Connor: Is Rayne Field unitized completely?

Mr. Head: Yes.

Commissioner Morgan: Did I understand you to say

this is leases from the owners of the land to the producers which you acquired?

Mr. Head: The owners of the land gave leases to Continental, et al. Continental, et al, then drilled and discovered gas. Thereafter, the leases which Continental, et al, acquired from the owners of the land—they assigned those leases to us.

Commissioner Morgan: All rights under the leases?

Mr. Head: All rights under the leases with the exception of, they reserved the oil, and they reserved a production payment on the liquids, and they reserved any rights below the then deepest producing horizon in the field.

2747

Commissioner Morgan: And they reserved the right to be the operator?

Mr. Head: No. We entered into a separate management agreement with Continental because Continental had drilled some 18 wells. These are very high-pressure wells; very deep wells.

We entered into an agreement and asked them to manage. Under that management they are able to manage the wells better than Texas Eastern, since they had all the experience of drilling them.

Commissioner Ross: Do you have some of your own wells in this area too?

Mr. Head: In this area?

Commissioner Ross: Rayne Field area, just adjacent to it?

Mr. Head: No, we have no production adjacent to Rayne.

Commissioner O'Connor: Can you cancel the agreement with Continental?

Mr. Head: Under certain circumstances it can be cancelled.

Commissioner Ross: Would you be willing to?

Mr. Head: No, I think it is a good agreement. Staff tells you, Continental tells us whether the wells will be drilled or not. The management contract says "No well shall be drilled, nor shall any existing well be deepened below the casing previously set therein, without the consent of Louisiana Gas."

2748

We call the shots on the wells, where they are to be drilled, and what-not.

Commissioner O'Connor: What about the production of the gas? Do you call the shots on that?

Mr. Head: We call the shots on that. Under the Management Agreement we specifically file the nominations for the gas. We control nominations, so we control the production, which means we control the reservoirs from which they are produced.

Of course, the allowables are set by the Louisiana Conservation, but we are the ones, under the specific terms of the management agreement that have charge of that.

Commissioner Ross: What would happen to Continental's finances if you didn't take any gas out of this field for four or five years, or a very, very minimum amount?

Aren't they expecting as a part of this whole agreement to get a reasonable amount of money from their liquids?

Mr. Head: Their liquid revenues would drop off, yes.

Commissioner O'Connor: Staff counsel made the statement that, or gave the impression to me that Continental had determined the production of liquids because they could determine the rate. I guess that is not right—they determine which formation it is in. Does Continental have the right to determine which formation gas can be produced from?

Mr. Head: No. I pointed out to you, the agreement

specifically provides "nominations for the production shall be made by Louisiana Gas, or the purchaser of the gas."

Commissioner O'Connor: That includes nominations specifically?

Mr. Head: That includes all formations. The only thing Continental has control over, they won't produce it over the maximum efficient rate of flow, but as long as the allowable set by the Conservation Commission is within the M.E.R. of the well, Continental has no say-so over it at all. He has misconstrued the agreement honestly in that respect, and the agreement which is in the record will speak for itself.

Now, also, staff counsel is concerned about the fact that we require Continental to maintain a very high rate of deliverability from this field. He is concerned about the fact that Texas' Eastern said we don't want to confine ourselves and agree that we will take in accordance with a very specific rate of production. Obviously, we require that high deliverability and we are unwilling to commit ourselves to take in accordance with a specific rate of production, because we want the high deliverability for flexibility.

We want to be able to swing on this field, and that is the reason we require them to have a large amount of gas available for use at all times.

Commissioner Ross: I am just curious, why did you think this management agreement was not relevant to this proceeding,

2750

originally?

Mr. Head: Originally? I still don't really feel the Management Agreement is relevant, because it simply deals with the mechanics of operating the wells.

(2750)

But we, as owners of the leases—in other words, it could be with John Doe or anyone else you hired to operate the wells for you. It doesn't really affect the price or anything else.

As he points out, what we pay them under the management agreement, we get back under the reserved production payment. Again, we have answered most of what staff counsel has said in our brief, but I want to bring out one thing.

* * * * * * * * * *

2751

Now, getting back to the other parties, the New York Public Service Commission and U.G.I. all say they are interested only in the cost to the consumer, or cost at the marketplace; yet they go back and say, "Give Texas Eastern a 20-cent price for the CATCO gas down here."

As we pointed out, CATCO gas, cost to the consumer and cost at the marketplace—

Commissioner O'Connor: You mean give Tennessee?

Mr. Head: All right. The cost of the CATCO gas on shore

2752

is 24 cents; that is what it costs the consumer. When you get up to Rayne, it is 27 or 28 cents. That is what CATCO costs the consumer they are interested in. Rayne is far below CATCO on a proper comparable basis.

I was most interested in the fact that the New York Commission and U.G.I. both apparently admit that at the time Texas Eastern purchased the Rayne field it was a prudent investment in the light of those circumstances, but for some reason they now feel because circumstances have changed, that Texas Eastern must be penalized.

Well, I submit it is a sound regulatory principle that a

prudent investment at the time it is made is what must be considered in fixing the rates of any public utility.

For example, if U.G.I. today builds a long pipeline, and it has to pay a high—or it pays today's price for that pipe —but next year pipe is reduced to one-half of that, certainly I think U.G.I. would want to earn on its reasonable and prudent investment for what it paid for that pipe today, not what the pipe is worth next year.

2753

Counsel for U.G.I. also pointed out that every case that has been remanded by the courts has resulted in hardships. It has resulted in hardship, but it has not resulted in confiscation. This Commission in reducing the rates to the Catco producers did not confiscate their property. This Commission found that under those rates the Catco producers would realize a reasonable return on their properties. Any condition in Texas Eastern's order which would require them to take less than the cost of the Rayne gas would obviously be confiscatory.

• • • • • • • • • •

3746

DeGolyer and MacNaughton
5625 Daniels Avenue
Dallas, Texas

Federal Power Commission

Docket No. ....

Hearing Exhibit No. X-2

Witness ....

ESTIMATED RESERVES AND AVAILABILITY
of
RESIDUE GAS, CONDENSATE and
PLANT LIQUIDS
of
TEXAS EASTERN TRANSMISSION CORPORATIO
in the
RAYNE FIELD, ACADIA PARISH, LOUISIANA
as of
JANUARY 1, 1961

ESTIMATED RESIDUE GAS, CONDENSATE and PLANT LIQUIDS RESERVES
of
TEXAS EASTERN TRANSMISSION CORPORATION
in the
RAYNE FIELD, ACADIA PARISH, LOUISIANA
as of
JANUARY 1, 1961

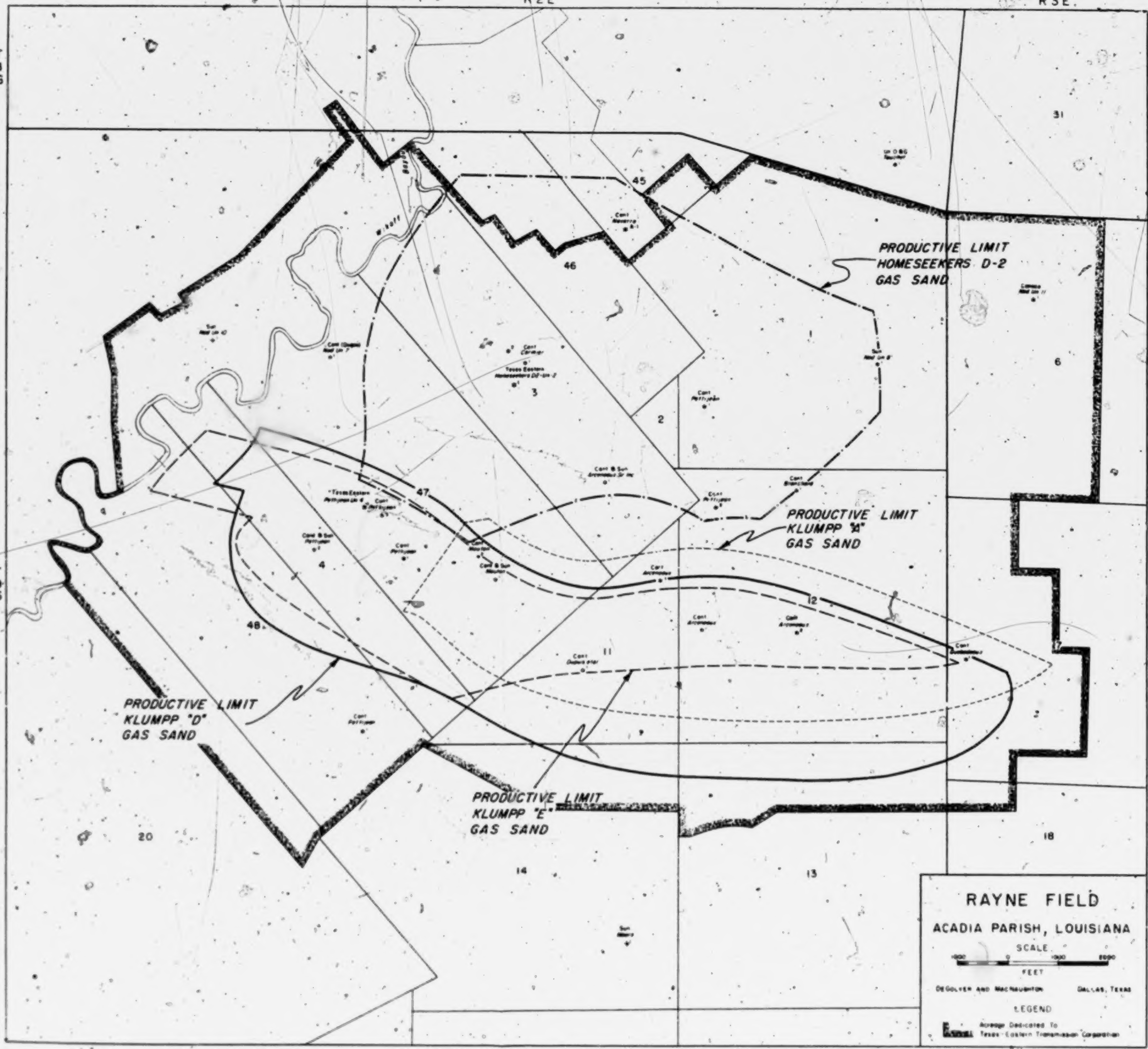
(All Volumes Expressed at 14.73 Psia Base Pressure and 60 Degrees Fahrenheit)

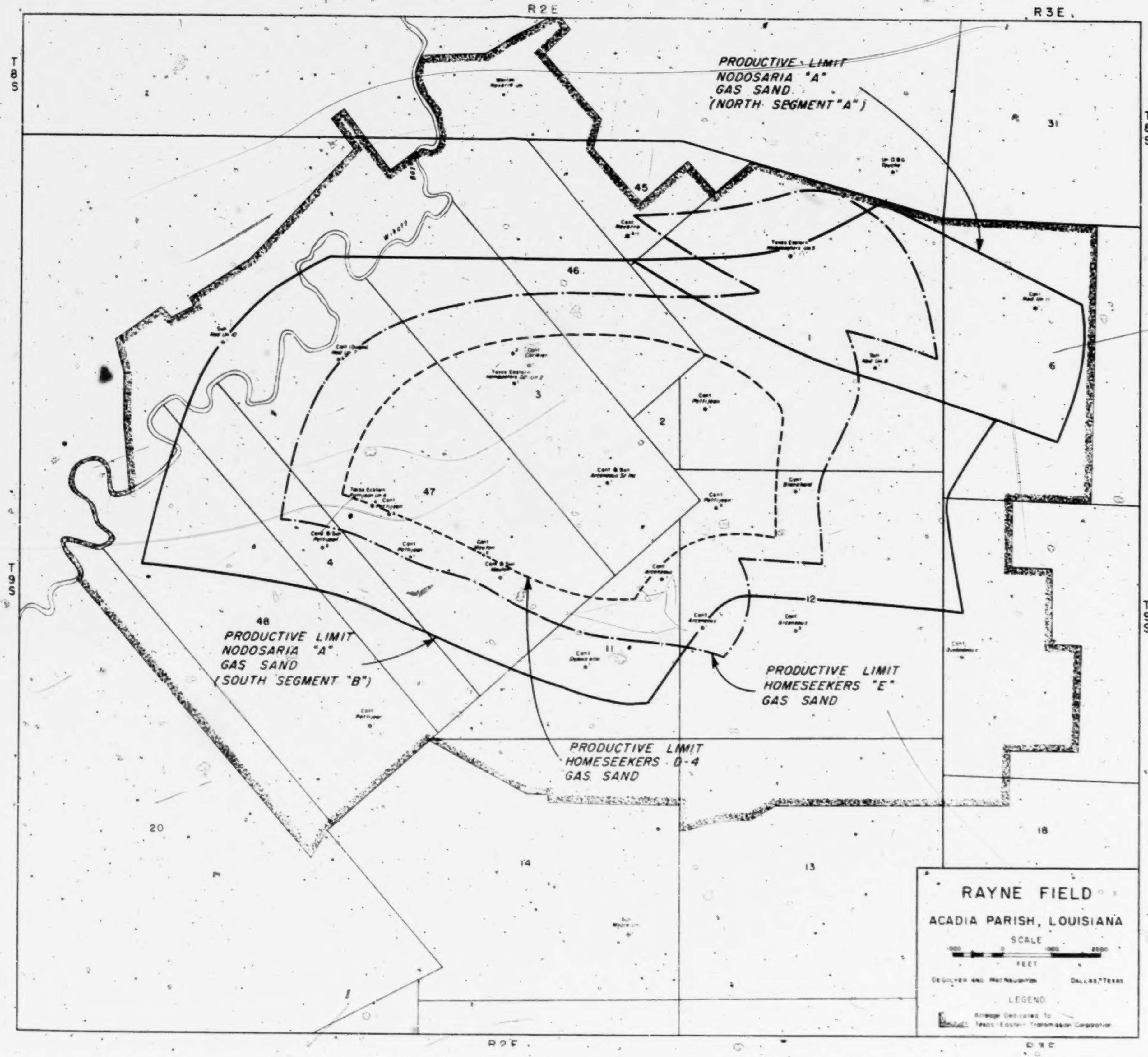
Line Number (a)	Item (b)	Units (c)	Klumpp "A" Sand (d)	Klumpp "D" Sand (e)	Klumpp "E" Sand (f)	Homeseekers "D-2" Sand (g)	Homeseekers "D-4" Sand (h)	Homeseekers "E" Sand (i)	Nodosaria North Seg. "A" (j)
1	Type of Gas		Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated
2	Average Depth	Feet	10,740	11,250	11,360	11,790	12,190	12,620	13 700
3	Number of Well Completions		1	4	1	2	0	6	2
4	Estimated Productive Area	Acres	743	1,240	703	1,313	770	1,686	498
5	Estimated Average Thickness	Feet	13.2	29.4	11.3	12.0	8.8	73.9	78.9
6	Estimated Reservoir Volume	Acre-Feet	9,787	36,462	7,935	15,758	6,739	124,637	39,273
7	Estimated Average Porosity	Percent	23.8	21.8	24.9	24.8	24.7	24.6	20.5
8	Estimated Interstitial Water	Percent	34.0	22.5	22.7	30.0	30.0	19.0	14.9
9	Reservoir Temperature	Degrees, F.	222	230	232	239	245	252	269
10	Initial Reservoir Pressure	Psia	4,835	6,855	6,868	7,520	8,125	8,918	11,008
11	Terminal Reservoir Pressure	Psia	515	515	515	515	515	515	515
12	Compressibility Factor, Initial Conditions		0.990	1.150	1.145	1.215	1.262	1.310	1.465
13	Compressibility Factor, Terminal Conditions		0.962	0.965	0.965	0.964	0.968	0.973	0.975
14	Initial Gas in Place per Acre-Foot	Mcf	1,728	2,245	2,565	2,363	2,429	2,926	2,767
15	Terminal Gas in Place per Acre-Foot	Mcf	190	201	228	204	201	228	194
16	Estimated Initial Gas in Place	MMcf	16,912	81,857	20,353	37,236	16,369	364,688	108,668
17	Estimated Terminal Gas in Place	MMcf	1,860	7,329	1,809	3,215	1,355	28,417	7,619
18	Estimated Initial Recoverable Gas	MMcf	15,052	74,528	18,544	34,021	15,014	336,271	101,049
19	Estimated Cumulative Production to January 1, 1961	MMcf	0	7,783	0	1,877	0	26,412	6,901
20	Remaining Gas in Place on January 1, 1961	MMcf	16,912	74,074	20,353	35,359	16,369	338,276	101,767
21	Estimated Remaining Recoverable Gas	MMcf	15,052	66,745	18,544	32,144	15,014	309,859	94,148
22	Estimated Shrinkage Losses	MMcf	774	3,311	920	1,768	751	23,208	4,915
23	Estimated Residue Gas Reserves	MMcf	14,278	63,434	17,624	30,376	14,263	286,651	89,[illegible]3
24	Reserves Dedicated by Texas Eastern								
25	Dedicated Acre-Feet		9,787	36,462	7,935	13,946	6,739	124,637	39,273
26	Percent of Total Reservoir		100.00	100.00	100.00	88.50	100.00	100.00	100.00
27	Residue Gas Reserve	MMcf	14,278	63,434	17,624	26,883	14,263	286,651	89,233
28	Estimated Remaining Condensate Reserves	Barrels	226,185	1,116,575	333,623	624,281	337,225	8,352,067	1,628,918
29	Estimated Remaining Plant Liquids Reserves	Barrels	197,533	763,200	220,915	408,924	257,772	6,767,991	984,574

ESTIMATED RESIDUE GAS, CONDENSATE and PLANT LIQUIDS RESERVES
of
TEXAS EASTERN TRANSMISSION CORPORATION
in the
RAYNE FIELD, ACADIA PARISH, LOUISIANA
as of
JANUARY 1, 1961

(All Volumes Expressed at 14.73 Psia Base Pressure and 60 Degrees Fahrenheit)

Klumpp "A" Sand (d)	Klumpp "D" Sand (e)	Klumpp "E" Sand (f)	Homeseekers "D-2" Sand (g)	Homeseekers "D-4" Sand (h)	Homeseekers "E" Sand (i)	Nodosaria "A" Sand North Seg. "A" (j)	Nodosaria "A" Sand South Seg. "B" (k)	Nodosaria "A" Sand Subtotal (l)	TOTAL (m)	Line Number (n)
Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated	Non-Associated			1
10,740	11,250	11,360	11,790	12,190	12,620	13 700	13,640			2
1	4	1	2	0	6	2	7			3
743	1,240	703	1,313	770	1,686	498	2,423			4
13.2	29.4	11.3	12.0	8.8	73.9	78.9	80.2			5
9,787	36,462	7,935	15,758	6,739	124,637	39,273	194,230			6
23.8	21.8	24.9	24.8	24.7	24.6	20.5	20.5			7
34.0	22.5	22.7	30.0	30.0	19.0	14.9	14.9			8
222	230	232	239	245	252	269	268			9
4,835	6,855	6,868	7,520	8,125	8,918	11,008	10,972			10
515	515	515	515	515	515	515	515			11
0.990	1.150	1.145	1.215	1.262	1.310	1.465	1.460			12
0.962	0.965	0.965	0.964	0.968	0.973	0.975	0.975			13
1,728	2,245	2,565	2,363	2,429	2,926	2,767	2,767			14
190	201	228	204	201	228	194	195			15
16,912	81,857	20,353	37,236	16,369	364,688	108,668	537,434	646,102	1,183,517	16
1,860	7,329	1,809	3,215	1,355	28,417	7,619	37,875	45,494	89,479	17
15,052	74,528	18,544	34,021	15,014	336,271	101,049	499,559	600,608	1,094,038	18
0	7,783	0	1,877	0	26,412	6,901	39,441	46,342	82,414	19
16,912	74,074	20,353	35,359	16,369	338,276	101,767	497,993	599,760	1,101,103	20
15,052	66,745	18,544	32,144	15,014	309,859	94,148	460,118	554,266	1,011,624	21
774	3,311	920	1,768	751	23,208	4,915	47,806	52,721	83,453	22
14,278	63,434	17,624	30,376	14,263	286,651	89,233	412,312	501,545	928,171	23
										24
9,787	36,462	7,935	13,946	6,739	124,637	39,273	194,230			25
100.00	100.00	100.00	88.50	100.00	100.00	100.00	100.00			26
14,278	63,434	17,624	26,883	14,263	286,651	89,233	412,312	501,545	924,678	27
226,185	1,116,575	333,623	624,281	337,225	8,352,067	1,628,918	16,967,482	18,596,400	29,586,356	28
197,533	763,200	220,915	408,924	257,772	6,767,991	984,574	12,211,943	13,196,517	21,812,852	29


R2E
R3E
T8S
T9S
PRODUCTIVE LIMIT
HOMESEEKERS D-2
GAS SAND
PRODUCTIVE LIMIT
KLUMPP "A"
GAS SAND
PRODUCTIVE LIMIT
KLUMPP "D"
GAS SAND
PRODUCTIVE LIMIT
KLUMPP "E"
GAS SAND
RAYNE FIELD
ACADIA PARISH, LOUISIANA
SCALE
FEET
DeGOLYER AND MacNAUGHTON
DALLAS, TEXAS
LEGEND
Acreage Dedicated To
Texas Eastern Transmission Corporation


R2E
R3E
T8S
T9S
PRODUCTIVE LIMIT
NODOSARIA "A"
GAS SAND
(NORTH SEGMENT "A")
PRODUCTIVE LIMIT
NODOSARIA "A"
GAS SAND
(SOUTH SEGMENT "B")
PRODUCTIVE LIMIT
HOMESEEKERS "E"
GAS SAND
PRODUCTIVE LIMIT
HOMESEEKERS D-4
GAS SAND
RAYNE FIELD
ACADIA PARISH, LOUISIANA
SCALE
FEET
LEGEND

3751

Exhibit No. X-3
Dockets Nos. G-12446 and G-12447
Order dated July 14, 1961,
paragraph (B)(3)

TEXAS EASTERN TRANSMISSION CORPORATION

PROPOSED METHOD OF ACCOUNTING RAYNE FIELD

FEDERAL POWER COMMISSION
Docket No. G-12446 et al.

Hearing Exhibit No. X-3

Date Identified 10-23-61
Date Admitted 12-7-61

Texas Eastern Transmission Corporation proposes the following method of accounting for the Rayne Field transaction and all costs incident thereto:

1. Texas Eastern will charge to Account 101—Gas Plant in Service the cost of producing leaseholds, producing gas wells, and structures and equipment related thereto.

2. Texas Eastern will charge to Account 404.1—Amortization and Depletion of Producing Natural Gas Land and Land Rights and will credit Account 111.1—Reserve for Amortization and Depletion of Producing Natural Gas Land and Land Rights with the depletion of natural gas producing leaseholds and amortization of intangible drilling costs on the unit-of-production basis.

3. Texas Eastern will charge Account 403—Depreciation Expense and will credit Account 108—Reserve for Depreciation of Gas Plant in Service with the depreciation of tangible producing plant on a unit-of-production basis.

(3751)

4. Texas Eastern will charge Account 186—Miscellaneous Deferred Debits and credit Account 131—Cash with the payment of the notes over the period of 15⅔ years.

5. Texas Eastern will charge Account 404.1—Amortization and Depletion of Producing Natural Gas Land and Land Rights and credit Account 186—

3752

Miscellaneous Deferred Debits with the amortization of note payments over the life of the Rayne Field reserves on unit-of-production basis.

6. Texas Eastern will credit Account 400—Operating Revenues with the revenue received from the sale of liquids after the production payment has been satisfied.

7. Texas Eastern will charge to Accounts 401—Operation Expense and 402—Maintenance Expense the cost of operating the Rayne Field after the completion of the production payments.

Years 1961 through 1989 | Order Dated July 14, 1961, Paragraph (B) (4)

Line No.	(A) Year	(B) Depletion of Gas Reserve	(C) Depreciation of Tangible Plant	(D) Depletion of Nat'l Gas Prod. Leaseholds	(E) Amortization of Intangible Drilling Costs	(F) Net Liquids Revenues	(G) Total Cost of Gas	(H) Cost Per MCF
1	1961	$ 6,492,600	$ 258,300	$ 439,700	$ 26,000	$ —	$ 7,216,600	17.31¢
2	1962	6,492,600	261,900	439,700	26,000	—	7,220,200	17.32
3	1963	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
4	1964	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
5	1965	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
6	1966	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
7	1967	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
8	1968	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
9	1969	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
10	1970	6,492,600	293,000	439,700	57,100	—	7,282,400	17.47
11	1971	6,492,600	293,000	439,700	57,100	(900)	7,281,500	17.47
12	1972	6,492,600	328,100	439,700	92,300	(1,000)	7,281,400	17.47
13	1973	6,492,600	374,800	439,700	133,500	(49,300)	7,303,400	17.52
14	1974	5,736,400	333,900	388,400	117,900	(80,800)	7,359,800	17.65
15	1975	4,772,100	277,700	323,200	98,100	(76,300)	6,500,300	17.65
16	1976	4,136,700	240,800	280,100	85,100	(1,674,200)	3,796,900	12.39
17	1977	3,582,300	221,600	242,600	104,200	(1,638,500)	3,104,200	11.69
18	1978	2,954,500	196,200	200,000	117,300	(1,337,000)	2,813,700	12.23
19	1979	2,580,600	171,400	174,700	102,500	(1,021,500)	2,446,500	12.90
20	1980	2,097,100	149,400	142,000	106,900	(887,800)	2,141,400	12.92
21	1981	1,772,400	153,900	120,000	154,700	(659,400)	1,836,000	13.63
22	1982	1,471,300	145,900	99,600	170,100	(568,200)	1,632,800	14.35
23	1983	901,800	99,700	61,100	128,800	(421,100)	1,465,800	15.51
24	1984	755,900	83,500	51,200	108,000	(116,300)	1,075,100	18.57
25	1985	626,200	69,200	42,400	89,400	(181,900)	816,700	16.83
26	1986	570,400	63,000	38,600	81,500	(129,200)	698,000	17.36
27	1987	511,700	56,600	34,700	73,100	(91,100)	662,400	18.08
28	1988	324,700	35,900	22,000	46,400	(51,600)	624,500	19.00
29	1989	289,100	31,900	19,600	41,100	(36,000)	393,000	18.85
						(9,100)	372,600	20.09
	Totals	$117,487,000	$6,190,700	$7,956,300	$2,416,800	$(9,031,200)	$125,019,600	16.57¢

NOTE: In addition to the above costs, the Rayne Field leases obligate Texas Eastern to account to the royalty owners for the royalty portion of the gas on the basis of the market value at the well as and when produced and saved. Texas Eastern will also be obligated to account to the State of Louisiana for production or severance taxes imposed on the working interest gas.

3754

Hearing Exhibit No. X-5

TEXAS EASTERN TRANSMISSION CORPORATION

ESTIMATED RESIDUE GAS PRODUCTION
RAYNE FIELD
ACADIA PARISH, LOUISIANA
1961 THRU 1989

Year	Annual Production (MMCF)
1961	51,100
1962	51,100
1963	51,100
1964	51,100
1965	[illegible]1,100
1966	51,100
1967	51,100
1968	51,100
1969	51,100
1970	51,100
1971	51,100
1972	51,100
1973	51,100
1974	45,148
1975	37,558
1976	32,557
1977	28,194
1978	23,254
1979	20,311
1980	16,505
1981	13,949
1982	11,580
1983	7,098
1984	5,950
1985	4,928
1986	4,490
1987	4,028
1988	2,555
1989	2,273
Total	924,678

FEDERAL POWER COMMISSION
Docket No. G-12446

Hearing Exhibit No. X-5

Date Identified 10-23-61
Date Admitted 12-7-61

3755

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COST OF NEW WELLS
(Non-Recoverable From Liquid Revenues)

	No. of Wells		Cost of Wells		
Year	Dual Compl.	Single Compl.	Tangible	Intangible	Total
1962	2	0	$ 500,000	$ 500,000	$1,000,000
1971	1	0	250,000	250,000	500,000
1972	1	0	250,000	250,000	500,000
Total	4	0	$1,000,000	$1,000,000	$2,000,000

Tangible 50%
Intangible 50%

3756

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COST OF WELL WORKERS

	Tangible		Intangible		
Year	Recoverable	Non-Recoverable	Recoverable	Non-Recoverable	Total
1962	$ 21,300	$—	$ 49,700	$—	$ 71,000
1963	22,500	—	52,500	—	75,000
1967	22,500	—	52,500	—	75,000
1971	22,493	7	52,484	16	75,000
1972	22,153	347	51,689	811	75,000
Total	$110,946	$354	$258,873	$827	$371,000

Tangible 30%
Intangible 70%

3757

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
TUBING REPLACEMENT COSTS

	Tangible		Intangible		
Year	Recoverable	Non-Recoverable	Recoverable	Non-Recoverable	Total
1968	$ 22,500	$ —	$ 52,500	$ —	$ 75,000
1969	90,000	—	210,000	—	300,000
1970	157,463	37	367,415	85	525,000
1971	179,945	55	419,871	129	600,000
1976	—	67,500	—	157,500	225,000
1977	—	67,500	—	157,500	225,000
1979	—	45,000	—	105,000	150,000
1980	—	112,500	—	262,500	375,000
1981	—	67,500	—	157,500	225,000
1982	—	45,000	—	105,000	150,000
Total	$449,908	$405,092	$1,049,786	$945,214	$2,850,000

Tangible 30%
Intangible 70%

3758

Docket No. G-12446
Exhibit No. X-5
Page No. 5

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COST OF TIE-IN FACILITIES

Year	Tangible Recoverable	Non-Recoverable	Total
1962	$180,000	$ —	$180,000
1971	89,972	28	90,000
1972	88,611	1,389	90,000
Total	$358,583	$1,417	$360,000

3759

Docket No. G-12446
Exhibit No. X-5
Page No. 6

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COST OF LOW PRESSURE GATHERING SYSTEM

Year	Total[1]
1964	$125,000
1965	125,000
1966	125,000
1967	125,000
1968	50,000
Total	$550,000

[1] All Costs Tangible and Recoverable.

Docket No. G-12446
Exhibit No. X-5
Page No. 7

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COST OF FIELD COMPRESSION FACILITIES

Year	Recoverable	Non-Recoverable	Total
1964	$ 300,000	$ —	$ 300,000
1966	300,000	—	300,000
1968	1,500,000	—	1,500,000
1972	2,067,556	32,444	2,100,000
1973	583,948	16,052	600,000
Total	$4,751,504	$48,496	$4,800,000

Tangible 100%

Docket No. G-12446
Exhibit No. X-5
Page No. 8.

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
WELL OPERATING COSTS AND MAINTENANCE

Year	Recoverable	Non-Recoverable	Total
1961	$ 383,040	$ —	$ 383,040
1962	383,040	—	383,040
1963	455,040	—	455,040
1964	455,040	—	455,040
1965	455,040	—	455,040
1966	455,040	—	455,040
1967	455,040	—	455,040
1968	396,000	—	396,000
1969	396,000	—	396,000
1970	395,909	91	396,000
1971	395,879	121	396,000
1972	425,324	6,676	432,000
1973	455,477	12,523	468,000
1974	453,969	14,031	468,000
1975	75,662	392,338	468,000
1976	—	468,000	468,000
1977	—	468,000	468,000
1978	—	468,000	468,000
1979	—	450,000	450,000
1980	—	450,000	450,000
1981	—	396,000	396,000
1982	—	378,000	378,000
1983	—	378,000	378,000
1984	—	216,000	216,000
1985	—	216,000	216,000
1986	—	216,000	216,000
1987	—	216,000	216,000
1988	—	180,000	180,000
1989	—	180,000	180,000
Total	$6,035,500	$5,105,780	$11,141,280

Docket No. G-12446
Exhibit No. X-5
Page No. 9

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
COMPRESSOR OPERATING COSTS

Year	Recoverable	Non-Recoverable	Total
1964	$ 15,000	$ —	$ 15,000
1965	15,000	—	15,000
1966	30,000	—	30,000
1967	30,000	—	30,000
1968	105,000	—	105,000
1969	105,000	—	105,000
1970	104,977	23	105,000
1971	104,968	32	105,000
1972	206,759	3,241	210,000
1973	233,581	6,419	240,000
1974	218,254	6,746	225,000
1975	29,100	150,900	180,000
1976	—	165,000	165,000
1977	—	150,000	150,000
1978	—	120,000	120,000
1979	—	105,000	105,000
1980	—	90,000	90,000
1981	—	75,000	75,000
1982	—	60,000	60,000
1983	—	45,000	45,000
1984	—	45,000	45,000
1985	—	30,000	30,000
1986	—	30,000	30,000
1987	—	30,000	30,000
1988	—	15,000	15,000
1989	—	15,000	15,000
Total	$1,197,639	$1,142,361	$2,340,000

Docket No. G-12446
Exhibit No. X-5
Page No. 10

TEXAS EASTERN TRANSMISSION CORPORATION

Revenues From Sale of Condensate Attributable to Texas Eastern's Net Interest in Production

Year	Gross Condensate Barrels	Texas Eastern's Net Interest in Production (81.58729%) — During Production Payments: Barrels	Value	After Production Payments: Barrels	Value	Total: Barrels	Value
1961	2,267,589	1,850,064	$ 5,550,192	—	$ —	1,850,064	$ 5,550,192
1962	2,603,050	2,123,758	6,371,274	—	—	2,123,758	6,371,274
1963	2,251,350	1,836,815	5,510,445	—	—	1,836,815	5,510,445
1964	2,053,050	1,675,028	5,025,084	—	—	1,675,028	5,025,084
1965	2,049,050	1,671,764	5,015,292	—	—	1,671,764	5,015,292
1966	1,874,150	1,529,068	4,587,204	—	—	1,529,068	4,587,204
1967	1,774,785	1,447,999	4,343,997	—	—	1,447,999	4,343,997
1968	1,688,700	1,377,765	4,133,295	—	—	1,377,765	4,133,295
1969	1,588,700	1,296,177	3,888,531	—	—	1,296,177	3,888,531
1970	1,408,500	1,148,892	3,446,676	265	795	1,149,157	3,447,471
1971	1,270,800	1,036,493	3,109,479	318	954	1,036,811	3,110,433
1972	1,282,425	1,030,127	3,090,381	16,169	48,507	1,046,296	3,138,888
1973	1,244,978	988,568	2,965,704	27,176	81,528	1,015,744	3,047,232
1974	1,081,877	856,211	2,568,633	26,463	79,389	882,674	2,648,022
1975	878,444	115,868	347,604	600,831	1,802,493	716,699	2,150,097
1976	754,783	—	—	615,807	1,847,421	615,807	1,847,421
1977	650,427	—	—	530,666	1,591,998	530,666	1,591,998
1978	534,480	—	—	436,068	1,308,204	436,068	1,308,204
1979	478,334	—	—	390,260	1,170,780	390,260	1,170,780
1980	398,385	—	—	325,032	975,096	325,032	975,096
1981	344,119	—	—	280,757	842,271	280,757	842,271
1982	284,168	—	—	231,845	695,535	231,845	695,535
1983	182,670	—	—	149,036	447,108	149,036	447,108
1984	152,767	—	—	124,638	373,914	124,638	373,914
1985	126,881	—	—	103,519	310,557	103,519	310,557
1986	114,957	—	—	93,790	281,370	93,790	281,370
1987	102,581	—	—	83,693	251,079	83,693	251,079
1988	76,390	—	—	62,325	186,975	62,325	186,975
1989	67,966	—	—	55,452	166,356	55,452	166,356
Total	29,586,356	19,984,597	$59,958,791	4,154,110	$12,462,330	24,138,707	$72,416,121

Docket No. G-12446
Exhibit No. X-5
Page No. 12

TEXAS EASTERN TRANSMISSION CORPORATION

Revenues From Sale of Plant Liquids
Attributable to Texas Eastern's Net Interest in Production

TEXAS EASTERN TRANSMISSION CORPORATION

Revenues From Sale of Plant Liquids
Attributable to Texas Eastern's Net Interest in Production

Year	Gross Plant Liquids	Texas Eastern's Net Interest in Production (81.58729%)						60% of Net Interest in Production					
		During Production Payments		After Production Payments		Total		During Production Payments		After Production Payments		Total	
	Barrels	Barrels	Value	Barrels	Value	Barrels	Value	Barrels	Value	Barrels	Value	Barrels	Value
1961	1,260,193	1,028,157	$ 1,740,670	-	$ -	1,028,157	$ 1,740,670	616,894	$ 1,044,402	-	$ -	616,894	$ 1,044,402
1962	1,402,058	1,143,901	1,936,624	-	-	1,143,901	1,936,624	686,341	1,161,974	-	-	686,341	1,161,974
1963	1,255,318	1,024,180	1,733,937	-	-	1,024,180	1,733,937	614,508	1,040,362	-	-	614,508	1,040,362
1964	1,224,298	998,872	1,691,090	-	-	998,872	1,691,090	599,323	1,014,654	-	-	599,323	1,014,654
1965	1,265,245	1,032,279	1,747,648	-	-	1,032,279	1,747,648	619,367	1,048,589	-	-	619,367	1,048,589
1966	1,256,693	1,025,302	1,735,836	-	-	1,025,302	1,735,836	615,181	1,041,502	-	-	615,181	1,041,502
1967	1,325,112	1,081,123	1,830,341	-	-	1,081,123	1,830,341	648,674	1,098,205	-	-	648,674	1,098,205
1968	1,302,588	1,062,746	1,799,230	-	-	1,062,746	1,799,230	637,648	1,079,538	-	-	637,648	1,079,538
1969	1,271,464	1,037,353	1,756,239	-	-	1,037,353	1,756,239	622,412	1,053,743	-	-	622,412	1,053,743
1970	1,166,264	951,304	1,610,558	219	371	951,523	1,610,929	570,782	966,335	131	223	570,913	966,558
1971	1,086,172	885,907	1,499,840	271	459	886,178	1,500,299	531,544	899,904	163	275	531,707	900,179
1972	1,084,566	871,198	1,474,938	13,670	23,144	884,868	1,498,082	522,719	884,963	8,202	13,886	530,921	898,849
1973	1,108,567	880,253	1,490,268	24,197	40,966	904,450	1,531,234	528,152	894,161	14,518	24,580	542,670	918,741
1974	981,667	776,904	1,315,298	24,012	40,651	800,916	1,355,949	466,142	789,179	14,407	24,391	480,549	813,570
1975	812,785	107,208	181,503	555,921	941,175	663,129	1,122,678	64,325	108,902	333,553	564,705	397,878	673,607
1976	709,443	-	-	578,815	979,934	578,815	979,934	-	-	347,289	587,960	347,289	587,960
1977	617,685	-	-	503,952	853,191	503,952	853,191	-	-	302,371	511,915	302,371	511,915
1978	507,377	-	-	413,955	700,826	413,955	700,826	-	-	248,373	420,496	248,373	420,496
1979	453,899	-	-	370,324	626,959	370,324	626,959	-	-	222,194	376,175	222,194	376,175
1980	378,579	-	-	308,872	522,920	308,872	522,920	-	-	185,323	313,752	185,323	313,752
1981	327,515	-	-	267,211	452,388	267,211	452,388	-	-	160,327	271,433	160,327	271,433
1982	269,252	-	-	219,675	371,910	219,675	371,910	-	-	131,805	223,146	131,805	223,146
1983	165,234	-	-	134,810	228,233	134,810	228,233	-	-	80,886	136,940	80,886	136,940
1984	137,186	-	-	111,926	189,491	111,926	189,491	-	-	67,156	113,695	67,156	113,695
1985	114,030	-	-	93,034	157,507	93,034	157,507	-	-	55,820	94,504	55,820	94,504
1986	103,153	-	-	84,160	142,483	84,160	142,483	-	-	50,496	85,490	50,496	85,490
1987	92,042	-	-	75,095	127,136	75,095	127,136	-	-	45,057	76,282	45,057	76,282
1988	71,160	-	-	58,058	98,292	58,058	98,292	-	-	34,835	58,975	34,835	58,975
1989	63,307	-	-	51,650	87,443	51,650	87,443	-	-	30,990	52,466	30,990	52,466
Total	21,812,852	13,906,687	$23,544,020	3,889,827	$6,585,479	17,796,514	$30,129,499	8,344,012	$14,126,413	2,333,896	$3,951,289	10,677,908	$18,077,702

3765

Docket No. G-12446
Exhibit No. X-5
Page No. 12

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
PRODUCTION PAYMENT TERMINATION DATES

Conoco, et al	February	1975
Dishman, et al	April	1973
Muller	January	1972
Kirby	July	1972
Texas Gas	March	1970

3766

Docket No. G-12446
Exhibit No. X-5
Page No. 13

TEXAS EASTERN TRANSMISSION CORPORATION

RAYNE FIELD, ACADIA PARISH, LOUISIANA
DETERMINATION OF PERCENTAGE INTERESTS
BASED ON TOTAL RESERVES

	MCF	%
Conoco, et al	783,498,900	79.14129
Dishman, et al	7,817,000	9.78960
Muller	11,006,700	1.11179
Kirby	5,144,100	0.51961
Texas Gas	247,500	0.02500
Total Working Interest	807,714,200	81.58729
Other Interests	182,285,800	18.41271
Total Rayne Field	990,000,000	100.0%

Docket No. G-12446
Exhibit No. X-5
Page No. 14

TEXAS EASTERN TRANSMISSION CORPORATION

Rayne Field, Acadia Parish, Louisiana
Compressor Fuel and Gas For Field Use

	During Production Payments		After Production Payments		Total	
Year	MCF	Value	MCF	Value	MCF	Value
1964	88,000	$ 14,960	—	$ —	88,000	$ 14,9[illegible]
1965	88,000	14,960	—	—	88,000	14,9[illegible]
1966	175,000	29,750	—	—	175,000	29,7[illegible]
1967	175,000	29,750	—	—	175,000	29,7[illegible]
1968	613,000	104,210	—	—	613,000	104,2[illegible]
1969	613,000	104,210	—	—	613,000	104,2[illegible]
1970	612,860	104,186	140	24	613,000	104,2[illegible]
1971	612,812	104,178	188	32	613,000	104,2[illegible]
1972	1,207,058	205,200	18,942	3,220	1,226,000	208,[illegible]
1973	1,364,492	231,964	37,508	6,376	1,402,000	238,3[illegible]
1974	1,274,606	216,683	39,394	6,697	1,314,000	223,3[illegible]
1975	169,916	28,886	881,084	149,784	1,051,000	178,6[illegible]
1976	—	—	964,000	163,880	964,000	163,[illegible]
1977	—	—	876,000	148,920	876,000	148,[illegible]
1978	—	—	701,000	119,170	701,000	119,[illegible]
1979	—	—	613,000	104,210	613,000	104,[illegible]
1980	—	—	526,000	89,420	526,000	89,[illegible]
1981	—	—	438,000	74,460	438,000	74,[illegible]
1982	—	—	350,000	59,500	350,000	59,[illegible]
1983	—	—	263,000	44,710	263,000	44,7[illegible]
1984	—	—	263,000	44,710	263,000	44,7[illegible]
1985	—	—	175,000	29,750	175,000	29,7[illegible]
1986	—	—	175,000	29,750	175,000	29,7[illegible]
1987	—	—	175,000	29,750	175,000	29,7[illegible]
1988	—	—	88,000	14,960	88,000	14,[illegible]
1989	—	—	88,000	14,960	88,000	14,[illegible]
Total	6,993,744	$1,188,937	6,672,256	$1,134,283	13,666,000	$2,323,[illegible]

3768

Exhibit No. X-6
Witness: John P. Furman

UNITED STATES OF AMERICA FEDERAL POWER COMMISSION

Docket Nos. G-12446, et al.

In the Matters of

TEXAS EASTERN TRANSMISSION CORPORATION, et al.

EXHIBIT ACCOMPANYING
TESTIMONY OF JOHN P. FURMAN

FEDERAL POWER COMMISSION
Docket No. G-12446 et al.

Hearing Exhibit No. X-6

Date Identified 10-23-61
Date Admitted 12-7-61

FOSTER ASSOCIATES, INC.
Washington, D. C.

October 1961

3769

TABLE OF CONTENTS OF EXHIBIT

Page

3770

Identification

PRICES AND RELATED INFORMATION ON SALES IN SOUTH LOUISIANA TO PIPELINE COMPANIES UNDER LONG-TERM CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION, CONTRACTS DATED BETWEEN JANUARY 1, 1958 AND JUNE 30, 1959

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
HOPE NATURAL GAS COMPANY														
California Co., The	14	10/17/58	S. Bosco	Acadia	20	F	R	Yes	1,100	3,106.8	21.50	23.5	23.55	25.55
Callery Properties, Inc. et al.	G-17341	12/16/58	W. Rayne	Acadia	20	F	NR	NR	NR	NR	21.50	23.5	23.55	25.55
Continental Oil Co.	171	12/15/58	W. Rayne	Acadia	20	F	R	Yes	1,100	396.0	21.50	23.5	23.55	25.55
Tidewater Oil Co.	89	12/12/58	W. Rayne	Acadia	20	F	R	Yes	1,100	781.2	21.50	23.5	23.55	25.55
* Tidewater Oil Co.	91	12/12/58	S. Bosco	Acadia*	20	F	R	Yes	1,100	145.2	21.50	23.5	23.55	25.55
TEXAS GAS TRANSMISSION CORPORATION														
Cheyenne Oil Corp. of Delaware (Op.), et al.	2	8/15/58	Grand Coulee	Acadia	20	P	R	Yes	1,000	337.1	17.00	18.8	18.75	20.55
Texas National Petroleum Co. (Op.), et al.	6	1/30/59	Grand Coulee	Acadia	20	F	None	Yes	1,000	17.8	16.75	18.6	.8.50	20.35
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Jefferson Lake Sulphur (Op.), et al	2	1/7/58	N. Ellis	Acadia	Life	F	FN	Yes	1,000	157.2	16.00	17.9	17.50	19.40
UNITED FUEL GAS COMPANY														
Midwest Oil Corp. (Op.), et al.	14	12/29/58	Ellis	Acadia	20	F	R	Yes	1,000	937.9	17.60	20.3	19.10	21.80
Midwest Oil Corp. (Op.), et al.	15	12/29/58	Branch	Acadia	20	F	R	Yes	1,000	583.7	17.60	20.3	19.10	21.80
* Midwest Oil Corp. (Op.), et al.	20*	6/4/59	Ellis	Acadia	*	F	R	Yes	1,000	900.0	17.60	19.3	19.10	20.80
UNITED GAS PIPE LINE COMPANY														
* Carter, Reese E. (Op.), et al.	1	11/24/58	Maxie*	Acadia	20	P	R	No	1,000	611.7	18.50	20.7	20.25	22.45
Cities Service Petroleum Co.	106	1/2/58	S. Lewisburg	Acadia	20	F	R	Yes	1,000	192.0	18.50	20.7	20.25	22.45
Hudson Gas & Oil Corp., et al.	3	5/9/58	N.W. Branch	Acadia	20	F	R	No	1,000	262.5	18.50	20.7	20.25	22.45
Hunt Oil Co.	42	7/29/58	S. Mermentau	Acadia	20	P	R	No	1,000	397.3	18.50	20.7	20.25	22.45
Samedan Oil Corp. (Op.), et al.	4	1/16/59	Estherwood	Acadia	20	F	R	Yes	1,000	987.1	18.50	20.7	20.25	22.45
Sohio Petroleum Co.	42	1/10/58	S. Lewisburg	Acadia	20	F	R	Yes	1,000	1,500.0	18.50	20.7	20.25	22.45
Tidewater Oil Co.	71	5/5/58	Midland	Acadia	20	W	R	Yes	1,000	804.0	18.50	20.6	20.25	22.35
TEXAS GAS TRANSMISSION CORPORATION														
* Hunt, H. L.	18*	3/11/58	N. Elton*	Allen	20	P	R	Yes	1,000	6.7*	17.00	19.5	18.75	21.25

Source notes appear on page 12.
Footnotes appear on page 14.

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjust-ment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (¢/Mcf) (15.025) (l)	Average Base Price (¢/Mcf) (15.025) (m)	Initial Base Price Plus Tax (¢/Mcf) (15.025) (n)	Average Base Price Plus Tax (¢/Mcf) (15 025) (o)
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Beck Oil Co., et al.	1	11/15/58	Reeves	Allen	20	F	None	No	1,000	221.4	16.00	16.0	16.00	16.00
UNITED GAS PIPE LINE COMPANY														
Bel Oil Corp., et al.	6	8/1/58	Pilgrim Church	Allen	20	F	R	No	1,000	720.0	18.50	20.7	20.38	22.58
Hunt, H. L. (Op.), et al.	19	7/7/58	Pilgrim Church	Allen	20	F	R	No	1,000	398.4	18.50	20.7	20.38	22.58
Hunt Oil Co. (Op.), et al.	41	7/7/58	Castor Creek	Allen	20	F	R	No	1,000	361.9	18.50	20.7	20.38	22.58
Sands, Caroline Hunt	2	6/24/58	N.W. Oberlin	Allen	20	F	R	No	1,000	516.4	18.50	20.7	20.38	22.58
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Austral Oil Co., Inc.	3	12/30/58	Sorrento	Ascension	20	F	None	Yes	1,000	651.8	21.50	25.8	23.55	27.85
Brown, George R., et al.	5	12/30/58	Sorrento	Ascension	20	F	None	Yes	1,000	651.8	21.50	25.8	23.55	27.85
Humble Oil & Refining Co.	152	1/15/59	Sorrento	Ascension	20	F	None	Yes	1,000	474.7	21.50	25.8	23.55	27.85
COASTAL TRANSMISSION CORPORATION														
Irwin & Bess	1	6/24/59	Napoleonville	Assumption	20	F	None	Yes	1,000	157.7	18.00	19.8	19.75	21.55
TEXAS GAS TRANSMISSION CORPORATION														
Frankel, J. R.	3	3/30/59	E. Lake Palourde	Assumption	20	F	R	Yes	1,000	193.5	20.00	23.7	21.75	25.45
UNITED GAS PIPE LINE COMPANY														
Pan American Petroleum Corp.	228	[illegible]/25/58	Napoleonville	Assumption	20	F	R	No	1,000	277.5	18.50	20.6	20.00	22.10
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
* Hunt, H. L., et al.	25*	4/17/59*	Bear	Beauregard	20	F	None	Yes	1,000	14.3	21.50*	25.9*	23.55*	27.95
Hunt, H. L., et al.	29	4/17/59	Bear	Beauregard	20	F	None	Yes	1,000	24.0	21.50	25.9	23.55	27.95
* Jameson, F. E., et al.	2*	4/8/59	Bear	Beauregard	20	F	None	Yes	1,000	211.3	21.50	25.9	23.55*	27.95
* Mound Co., et al.	15*	3/7/58	Cowpen Creek	Beauregard	*	F	FN	Yes	1,000	438.1	16.00	17.9	17.75	19.65
* Shell Oil Co. (Op.), et al.	198*	3/3/59	Bear	Beauregard	20	F	None	Yes	1,000	1,030.7	21.50	25.9	23.55*	27.95
TRUNKLINE GAS COMPANY														
Cunningham, James M. (Op.), et al.	2	11/4/58	Oretta	Beauregard	21	F	None	Yes	1,000	345.7	16.60	18.6	18.10	20.10
* Lyons, C. H., Jr., et al.	4*	10/30/58	Ragley	Beauregard	*	F	FN	Yes	1,000	420.0	16.40	18.2	17.90	19.70
Penton, E. Doyle & Penton, D. N. d/b/a Penton & Penton (Op.), et al.	1	7/8/58	S. Bearhead Creek	Beauregard	22	F	None	Yes	1,000	249.8	16.40	18.6	17.90	20.10
Petroleum, Inc. (Op.), et al.	13	11/3/58	Various	Beauregard	21	F	None	No	1,000	901.2	16.60	18.6	18.10	20.10
Socony Mobil Oil Co., Inc.	159	3/27/58	NR	Beauregard	21	F	FN	Yes	1,000	192.0	16.40	18.4	17.90	19.90
Socony Mobil Oil Co., Inc.	165	7/7/58	Cowpen Creek	Beauregard	20	F	None	No	1,000	127.2	16.40	17.9	17.90	19.40
Texas Gulf Producing Co.	28	2/7/58	S.E. Fulton	Beauregard	20	F	FN	Yes	1,000	360.0	16.40	18.3	17.90	19.80

Footnotes appear on page 14.

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjust-ment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (¢/Mcf) (15.025) (l)	Average Base Price (¢/Mcf) (15.025) (m)	Initial Base Price Plus Tax (¢/Mcf) (15.025) (n)	Average Base Price Plus Tax (¢/Mcf) (15.025) (o)
UNITED GAS PIPE LINE COMPANY														
* Union Oil Co. of California	30*	4/20/59	Gordon	Beauregard	20	F	R	No	800	898.2	18.50	20.0	20.25*	21.75
COASTAL TRANSMISSION CORPORATION														
W. W. F. Oil Corp. (Op.), et al.	1	5/1/59	E. Buhler	Calcasieu	20	F	None	Yes	1,000	90.0	20.00	21.7	22.00	23.70
UNITED GAS PIPE LINE COMPANY														
Chance, R. L., Sr. (Op.), et al.	1	11/10/58	NR	Calcasieu	20	F	None	No	1,000	282.0	14.00	15.5	15.50	17.00
* General Crude Oil Co.	7*	6/5/58	Coward's Gully	Calcasieu*	20	F	None	No	1,000	372.0*	17.00	18.5	18.75	20.25
* Gulf Oil Corp. (Op.), et al.	161*	7/9/58	Hayes	Calcasieu*	20	W	R	No	800	4,815.0	20.50	21.8	22.80*	24.10
* Shell Oil Co. (Op.)	203*	4/30/59	Iowa	Calcasieu*	20	F	R	Yes	1,000	7,568.0	18.50	21.4	20.55*	23.45
AMERICAN LOUISIANA PIPE LINE COMPANY														
Fifteen Oil Co.	2	1/1/59	E. Cheniere Perdue	Cameron	20	W	FN,R	Yes	1,050	495.1	18.25	22.0	19.75	23.50
Humble Oil & Refining Co.	140	6/2/58	Cheniere Perdue	Cameron	20	F	FN,R	Yes	1,050	360.1	18.25	22.0	19.75	23.50
Humble Oil & Refining Co.	156	4/24/59	E. Cheniere Perdue	Cameron	20	F	FN,R	Yes	1,050	742.8	18.25	22.0	19.75	23.50
Kerr-McGee Oil Industries, Inc.	61	7/31/58	Big Lake	Cameron	20	F	FN,R	Yes	1,050	661.0	18.25	22.8	19.75	24.30
Pan American Petroleum Corp.	248	1/10/58	Big Lake	Cameron	21	F	FN,R	Yes	1,050	7,545.5	18.25	22.7	19.75	24.20
Tidewater Oil Co.	74	7/10/58	Second Bayou	Cameron	Life	F	FN,R	Yes	1,100	90.0	18.00	22.1	19.75	23.60
Tidewater Oil Co.	82	12/31/58	N. Holly Beach	Cameron	Life	F	FN,R	Yes	1,100	100.4	18.00	22.3	19.50	23.80
HOPE NATURAL GAS COMPANY														
Ocean Drlg. & Exploration Co.	1	10/23/58	Block 4, E. Cameron Area	Cameron (Offshore)	20	W	R	Yes	1,200	2,752.8	21.50	23.5	23.55	25.55
* Phillips Petroleum Co., et al.	355*	11/14/58	Block 33, W. Cameron Area	Cameron (Offshore)	20	W	R	Yes	1,200	17,304.0*	21.50	23.5	23.55	25.55
* Sands, Caroline Hunt, et al.	5	8/13/58	S. Thornwell	Cameron*	20	F	R	Yes	1,100	312.0	21.50	23.5	23.55	25.55
Socony-Mobil Oil Co., Inc.	203	11/4/58	Block 4, E. Cameron Area	Cameron (Offshore)	20	F	R	Yes	1,200	765.6	21.50	23.5	23.55	25.55
TENNESSEE GAS TRANSMISSION CORPORATION														
Continental Oil Co.	165	12/31/58	E. Cameron	Cameron	19	W	None	Yes	1,000	810.0	21.40	25.1	22.90	26.60
Newmont Oil Co.	4	12/30/58	E. Cameron	Cameron	19	F	None	Yes	1,000	270.0	21.40	25.1	22.90	26.60
Shell Oil Co.	180	5/8/58	Block 192, W. Cameron Area	Cameron (Offshore)	20	F	None	Yes	1,000	15,783.2	21.40	25.3	23.15	27.05
Socony Mobil Oil Co., Inc.	177	12/12/58	E. Cameron	Cameron	19	F	None	Yes	1,000	2,521.2	21.40	25.3	22.90	26.80

Footnotes appear on page 14.

Schedule 1
Sheet 4 of 17

FA-4606

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjust-ment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025)	Initial Base Price (¢/Mcf) (15.025) (l)	Average Base Price (¢/Mcf) (15.025) (m)	Initial Base Price Plus Tax (¢/Mcf) (15.025) (n)	Average Base Price Plus Tax (¢/Mcf) (15.025) (o)
TEXAS GAS TRANSMISSION CORPORATION														
Gulf Oil Corp.	152	9/26/58	Grand Lake Area	Cameron	20	F	None	Yes	1,000	342.4	17.00	18.8	18.75	20.55
TRUNKLINE GAS COMPANY														
Union Oil Co. of California	41	6/17/58	Block 67, W. Cameron Area	Cameron (Offshore)	23	W	None	Yes	1,200	5,021.1	22.00	26.3	22.00	26.30
UNITED FUEL GAS COMPANY														
Humble Oil & Refining Co.	145	9/24/58	Go Around Bayou	Cameron	20	F	FN,R	Yes	1,000	339.7	17.60	20.2	19.10	21.70
Kerr-McGee Oil Industries, Inc. (Op.), et al.	60	9/24/58	Go Around Bayou	Cameron	20	F	FN,R	Yes	1,000	552.7	17.60	20.2	19.10	21.70
Shell Oil Co.	177	5/13/58	E. Cameron	Cameron	20	F	FN,R	Yes	1,000	7,839.6	17.60	20.8	19.10	22.30
COASTAL TRANSMISSION CORPORATION														
* Amerada Petroleum Corp.	82	3/23/59	Lake Chicot	Iberia*	20	F	R	Yes	1,000	1,080.0	21.50	25.3	23.55	27.35
* Phillips Petroleum Co.	372	3/23/59	Lake Chicot	Iberia*	20	F	R	Yes	1,000	2,511.6	21.50	25.9	23.55	27.95
HOPE NATURAL GAS COMPANY														
Callery Properties, Inc., et al.	2	12/10/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	1,488.0	21.50	23.5	23.55	25.55
Continental Oil Co.	174	12/15/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	432.0	21.50	23.5	23.55	25.55
Humble Oil & Refining Co.	167	12/9/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	372.0	21.50	23.5	23.55	25.55
Kilroy Properties, Inc. et al.	3	12/8/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	744.0	21.50	23.5	23.55	25.55
Ocean Drilling & Exploration Co. (Op.), et al.	2	12/13/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	1,260.0	21.50	23.5	23.55	25.55
Pan American Petroleum Corp.	266	12/16/58	Jefferson Island	Iberia	21	F	R	Yes	1,100	409.2	21.00	23.0	23.05	25.05
* Richardson, Sid W., et al. d/b/a Richardson & Bass (Op.), et al.	2	10/17/58	Jefferson Island*	Iberia*	21	F	R	Yes	1,100	2,098.8	21.00	23.1	23.05	25.15
Shell Oil Co.	215	11/25/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	5,022.0	21.50	23.5	23.55	25.55
Tidewater Oil Co.	90	12/2/58	Jefferson Island	Iberia	21	F	R	Yes	1,100	114.0	21.00	23.1	23.05	25.15
Union Oil Co. of California	38	12/16/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,100	1,440.0	21.50	23.5	23.55	25.55
SOUTHERN NATURAL GAS COMPANY														
* California Co., The	13*	8/1/58	N. Bayou Long	Iberia	20	F	FN,R	Yes	1,100	852.9	21.50	25.5	23.68	27.68

Footnotes appear on pages 14 and 15.

Schedule 1
Sheet 5 of 17

FA-4606

Purchaser / Filing Company (a)	Rate Sch. No (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjust-ment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (¢/Mcf) (15.025) (l)	Average Base Price (¢/Mcf) (15.025) (m)	Initial Base Price Plus Tax (¢/Mcf) (15.025) (n)	Average Base Price Plus Tax (¢/Mcf) (15.025) (o)
SOUTHERN NATURAL GAS COMPANY														
Continental Oil Co.	166	12/16/58	Bayou Pigeon	Iberia	20	F	R	Yes	1,000	689.3	21.50	25.5	23.68	27.68
* Continental Oil Co	172*	4/30/59	Bayou Long	Iberia*	*	F	R	Yes	1,100	45.3	21.50	25.7	23.68	27.88
Continental Oil Co.	175	10/27/58	N. Bayou Long	Iberia	20	F	R	Yes	1,100	35.7	21.50	25.5	23.68	27.68
UNITED GAS PIPE LINE COMPANY														
* Shell Oil Co. (Op.), et al.	206*	4/30/59	Weeks Island	Iberia*	20	F	R	Yes	1,000	19,680.9	21.50	23.0	23.55 *	25.05
COASTAL TRANSMISSION CORPORATION														
Continental Oil Co.	G-20242	6/26/59	Thompson Bluff	Jefferson Davis	20	F	NR	NR	NR	180.0	20.00	24.3	22.18	26.48
HOPE NATURAL GAS COMPANY														
* Bel Oil Corp.	7	9/23/58	S. Thornwell	Jefferson Davis*	20	F	R	Yes	1,100	450.0	21.50	23.5	23.55	25.55
TEXAS GAS TRANSMISSION CORPORATION														
* Moore, Homer T.	1	3/5/59	Welsh	Jefferson Davis	20	F	None	Yes	1,000	12.0	12.00	13.9	13.75 *	15.65
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Pan American Petroleum Corp.	242	10/21/58	Lake Arthur	Jefferson Davis	21	F	None	Yes	1,000	3,492.8	21.50	25.8	23.55	27.85
UNITED GAS PIPE LINE COMPANY														
Delta Drilling Co.	26	3/27/59	Mermenteau	Jefferson Davis	20	F	R	No	1,000	641.5	17.00	18.5	18.50	20.00
Texaco Inc.	194	3/10/59	Welsh	Jefferson Davis	20	F	R	No	1,000	518.1	18.50	20.7	20.25	22.45
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
* Gulf Oil Corp.	163*	12/30/58	S. E. Rayne	Lafayette	Life	F	FN	Yes	1,000	45.6	16.00	18.0	17.50	19.50
* Tidewater Oil Co.	85*	2/26/59	S.E. Rayne	Lafayette	Life	F	FN	Yes	1,000	270.0	16.00	18.0	17.50	19.50
UNITED GAS PIPE LINE COMPANY														
* Crown Central Petroleum Corp.	7	9/22/58	N. Leroy	Lafayette*	20	F	O,R	Yes	1,025	168.0	20.50	22.0	22.25	23.75
* Monsanto Chemical Co. (Op.), et al.	28	4/1/58	Broussard	Lafayette*	20	F	R	No	1,000	751.6	18.50	20.7	20.25	22.45
* Tidewater Oil Co.	75	8/15/58	Ridge	Lafayette*	20	F	O,R	Yes	1,000	18.0	20.50	22.0	22.25	23.75
SOUTHERN NATURAL GAS COMPANY														
* Hunt, H. L.	30	4/2/58	Coffee Bay	Lafourche	20	F	R	Yes	1,000	6,558.8	20.50*	24.5*	22.55*	26.55

Footnotes appear on page 15.

Schedule 1
Sheet 6 of 17

PA-4606

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
TENNESSEE GAS TRANSMISSION COMPANY														
Kerr-McGee Oil Industries, Inc.	55	7/1/58	Bully Camp	Lafourche	20	F	FN,R	Yes	1,000	207.1	17.00	19.3	18.75	20.80
Pan American Petroleum Corp.	226	4/4/58	Bully Camp	Lafourche	20	F	FN,R	Yes	1,000	1,631.3	17.00	19.2	18.50	20.70
* Sinclair Oil & Gas Co. (Op.), et al.	167	7/17/58	Timbalier Bay	Lafourche*	20	F	FN,R	Yes	1,000	15.0	17.00	19.3	18.50	20.80
* Sohio Petroleum Co.	50*	7/17/58	Timbalier Bay	Lafourche	*	F	FN,R	Yes	1,000	19.2	17.00	19.3	18.50	20.80
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Barnhart, Paul F.	16	3/2/59	Thibodaux	Lafourche	20	F	None	Yes	1,000	1,639.8	21.50	25.8	23.55	27.85
* Cities Service Production Co. (Op.), et al.	7*	9/4/58	Chegby	Lafourche*	22	F	None	Yes	1,000	573.7	21.50	26.0	23.55	28.05
Frankel, R. R.	2	6/20/58	Chegby	Lafourche	22	F	R	Yes	1,000	635.9	21.50	26.2	23.30	28.00
Humble Oil & Refining Co.	130	2/11/58	Thibodaux	Lafourche	21	F	None	Yes	1,000	2,658.4	21.50	25.6	23.30	27.40
Humble Oil & Refining Co.	131	2/11/58	Rousseau	Lafourche	20	F	None	Yes	1,000	1,748.8	21.50	25.5	23.30	27.30
* Hunt Oil Co.	50*	4/30/59	Thibodaux	Lafourche	*	F	None	Yes	1,000	26.2	21.50	25.8	23.55	27.85
Republic Natural Gas Co., et al.	23	9/2/58	Raceland	Lafourche	20	F	None	Yes	1,000	619.9	21.50	25.7	23.55	27.75
* Sword Co., et al.	1*	2/16/59	Raceland	Lafourche	*	F	None	Yes	1,000	313.4	21.50	25.8	23.55	27.55
UNITED FUEL GAS COMPANY														
Drew Petroleum, Inc. (Op.), et al.	1	7/23/58	Valentine	Lafourche	20	F	None	Yes	1,100	190.9	16.00	16.0	17.50	17.50
UNITED GAS PIPE LINE COMPANY														
Humble Oil & Refining Co.	158	4/20/59	Chacahoula	Lafourche	20	F	R	Yes	1,000	4,957.3	21.50	25.5	23.55	27.55
* Pan American Petroleum Corp.	227	4/30/58	Bourg	Lafourche*	20	F	R	Yes	1,200	545.7	18.50	20.6	20.00	22.10
SOUTHERN NATURAL GAS COMPANY														
Bateman, Earl G., d/b/a Bateman Drilling Co. (Op.), et al.	4	4/11/58	Felice Bayou	Plaquemines	20	F	R	Yes	1,000	618.3	19.00	23.0	20.75	24.75
Callery, Francis A. (Op.), et al.	15	2/1/58	Coquille Bay	Plaquemines	20	F	None	Yes	1,000	187.7	19.00	20.5	20.75	22.25
Hunt Oil Co.	40	4/2/58	Triumph	Plaquemines	20	F	R	Yes	1,000	181.6	21.50	25.5	23.55	27.55
Texaco Inc.	186	4/10/58	Felice Bayou	Plaquemines	20	F	R	Yes	1,000	309.1	19.00	23.0	20.50	24.[illegible]
TENNESSEE GAS TRANSMISSION COMPANY														
Gulf Oil Corp.	170	6/26/59	Lake Washington	Plaquemines	20	F	FN,R	Yes	1,000	840.0	21.30	25.1	23.60	27.40
Humble Oil & Refining Co.	163	5/18/59	Block 30, W. Delta Area	Plaquemines (Offshore)	20	F	FN,R	Yes	1,000	2,880.0	21.30	25.2	23.60	27.[illegible]
Humble Oil & Refining Co.	164	5/18/59	Lake Washington	Plaquemines	20	F	FN,R	Yes	1,000	2,520.0	21.30	25.1	23.60	27.40

Footnotes appear on page 15.

Page 6

Purchaser / Filing Company (a)	Rate Sch No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
TENNESSEE GAS TRANSMISSION COMPANY														
Humble Oil & Refining Co.	165	5/18/59	S. E. Pass	Plaquemines	20	F	FN,R	Yes	1,000	5,400.0	21.30	25.1	23.60	27.40
Hunt, Hassie, Trust	24	6/30/59	Block 24, S. Pass Area	Plaquemines (Offshore)	20	F	FN,R	Yes	1,000	540.0	21.30	25.1	23.60	27.40
Placid Oil Co.	24	3/3/59	Lake Washington	Plaquemines	20	F	FN,R	Yes	1,000	9,672.0	21.30	25.0	23.60	27.30
Rimrock Tidelands, Inc., et al.	6	5/25/59	Block 31, S. Pass Area	Plaquemines (Offshore)	20	F	FN,R	Yes	1,000	360.0	17.00	19.5	18.50	21.00
Shell Oil Co.	216	6/26/59	Lake Washington	Plaquemines	20	F	FN,R	Yes	1,000	360.0	21.30	25.1	23.60	27.40
Shell Oil Co.	61-104	6/29/59	Block 30, W. Delta Area	Plaquemines (Offshore)	20	F	FN,R	NR	NR	1,800.0	21.30	25.2	21.30	25.20
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Humble Oil & Refining Co.	128	2/11/58	Lucy	St. Charles	20	F	None	Yes	1,000	577.6	21.50	25.5	23.30	27.30
Humble Oil & Refining Co.	129	2/11/58	Lac des Allemands	St. Charles	20	F	None	Yes	1,000	3,549.2	21.50	25.5	23.30	27.30
* Republic Natural Gas Co., et al.	31	4/3/59	Lucy	St. Charles*	22	F	R	Yes	1,000	281.9	21.50	26.2	23.55	28.25
Hurley Oil & Gas Co. (Op.), et al.	8	1/18/59	Vacherie	St. James	20	W	None	Yes	1,000	325.4	21.00	23.1	23.05	25.15
McDermott, J. Ray & Co., Inc.	9	12/30/58	Vacherie	St. James	20	F	None	Yes	1,000	640.8	21.00	23.2	23.05	25.25
Union Texas Natural Gas Corp.	9	1/7/58	Lower Vacherie	St. James	22	F	None	Yes	1,000	1,881.3	21.50	26.0	23.55	28.05
COASTAL TRANSMISSION CORPORATION														
British-American Oil Producing Co., The	38	1/30/59	Shuteson	St. Landry	20	F	FN,R	Yes	1,000	2,232.0	20.00	24.3	22.48	26.48
UNITED FUEL GAS COMPANY														
Gulf Interstate Oil Co.	2	3/23/58	Savoy	St. Landry	20	F	None	Yes	1,000	360.0	17.20	20.7	18.70	21.60
UNITED GAS PIPE LINE COMPANY														
* Humble Oil & Refining Co.	136	5/22/58	American Island*	St. Martin	20	F	R	Yes	1,000	313.6	21.20	22.6	22.95	24.35
Ohio Oil Co., The	39	7/11/58	American Island	St. Martin	20	F	R	Yes	1,000	16.8	21.20	22.6	22.95	24.35
* Shell Oil Co. (Op.), et al.	207*	4/30/59	W. Lake Verret	St. Martin	20	F	R	Yes	1,000	3,389.0	21.50	23.0	23.55	25.05
Shell Oil Co.	213	6/29/59	Bell River	St. Martin	20	F	R	Yes	1,000	1,440.0	21.50	23.0	23.55	25.05
Trice Production Co.	8	9/22/58	St. Martinville	St. Martin	20	F	None	No	1,000	302.2	18.50	20.3	20.00	22.30

Footnotes appear on pages 15 and 16.

0FA-4606

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
TENNESSEE GAS TRANSMISSION COMPANY														
* Shell Oil Co.	220	6/29/59	Atchafalaya Bay	St. Mary*	20	F	FN,R	Yes	1,000	1,800.0	21.30	25.1	23.60	27.40
Texaco Inc.	187	9/7/58	Atchafalaya Bay	St. Mary	20	F	FN,R	Yes	1,000	870.2	17.00	19.3	18.50	20.80
TEXAS GAS TRANSMISSION CORPORATION														
* Southwest Gas Producing Co., Inc. (Op.), et al.	12*	6/18/58	Jeanerette	St. Mary	20	F	R	Yes	1,000	4,822.5*	19.00	20.8	20.75	22.55
UNITED GAS PIPE LINE COMPANY														
Atlantic Refining Co., The	197	4/9/59	Jeanerette	St. Mary	20	W	R	Yes	1,000	5,788.9	20.50	24.3	22.80	26.60
Atlantic Refining Co., The	204	4/1/59	Bayou Sale	St. Mary	Life	F	R	Yes	1,000	6,100.8	20.00	23.8	22.30	26.10
* Humble Oil & Refining Co.	148*	6/15/58	Yellow Bayou	St. Mary	20	F	R	No	1,000	3,872.3*	21.50	25.5	23.55	27.55
Shell Oil Co.	212	5/1/59	Cote Blanche Island	St. Mary	20	F	R	Yes	1,000	1,488.0	21.50	23.0	23.55	25.05
Sun Oil Co.	114	5/1/58	Belle Isle	St. Mary	20	F	R	Yes	1,050	14,630.4	21.50	26.1	23.80	28.40
TENNESSEE GAS TRANSMISSION COMPANY														
Placid Oil Co.	27	3/19/59	Caillou Island	Terrebonne	21	O	FN,R	Yes	1,000	450.0	21.30	25.2	23.60	27.50
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Cities Service Production Co.	9	1/2/58	S. Bourg	Terrebonne	20	F	None	Yes	1,000	30.2	21.50	25.8	23.55	27.85
Cities Service Production Co.	G-14355	1/2/58	Willow Woods	Terrebonne	20	F	NR	NR	NR	NR	21.50	25.5	23.00	27.00
* Hunt, Hassie, Trust	22*	6/19/59	N.W. Mosquito Bay*	Terrebonne	20	W	None	Yes	1,000	633.4*	21.50	25.9	23.55	27.95
Kerr-McGee Oil Industries, Inc.	69	11/14/58	Block 28 & 32, Ship Shoal Area	Terrebonne (Offshore)	22	W	None	Yes	1,000	6,750.0	22.00	26.4	22.00	26.40
Pan American Petroleum Corp.	G-17417	11/14/58	Ship Shoal Area	Terrebonne (Offshore)	22	F	NR	NR	NR	NR	22.00	26.4	24.05	28.45
Phillips Petroleum Co.	342	11/14/58	Block 32, Ship Shoal Area	Terrebonne (Offshore)	22	W	None	Yes	1,000	744.0	22.00	26.4	24.05	28.45
* Shell Oil Co.	200	3/23/59	Humphreys*	Terrebonne	20	F	None	Yes	1,000	3,160.6	21.50	25.9	23.55	27.95
Shell Oil Co.	208	3/6/59	Mosquito Bay	Terrebonne	20	F	None	Yes	1,000	375.2	21.50	25.9	23.55	27.95
Southern Natural Gas Co., Joint Venture	1	11/14/58	Block 28, Ship Shoal Area	Terrebonne (Offshore)	22	W	None	Yes	1,000	11,250.0	22.00	26.4	22.00	26.40

Footnotes appear on page 16.

Purchaser / Filing Company (a)	Rate Sch No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Sunray Mid-Continent Oil Co. (Op.), et al.	183	2/12/58	Pointe Au Fer	Terrebonne	20	F	None	Yes	1,000	1,726.9	21.50	25.5	23.55	27.55
Tidewater Oil Co.	80	1/8/58	S. Bourg	Terrebonne	20	F	None	Yes	1,000	172.7	21.50	25.5	23.55	27.55
Union Oil Co. of California	25	1/10/58	Willow Woods	Terrebonne	20	F	None	Yes	1,000	82.4	21.50	26.0	23.30	27.80
UNITRD GAS PIPE LINE COMPANY														
Argo Oil Corp.	38	12/10/58	Sunrise	Terrebonne	20	F	R	Yes	1,050	1,036.7	20.00	21.5	22.05	23.55
California Co., The	11	7/21/58	Bayou Penchant	Terrebonne	20	F	R	Yes	1,000	7,316.1	21.50	25.4	23.80	27.70
Freeport Oil Co.	1	6/13/58	Sunrise	Terrebonne	20	W	R.	Yes	1,050	44.4	20.00	21.5	22.05	23.55
Humble Oil & Refining Co.	149	12/5/58	N.E. Gibson	Terrebonne	20	F	R	No	1,000	1,458.1	18.50	20.8	20.25	22.55
Lyons & Logan (Op.), et al.	9	3/1/58	Gibson	Terrebonne	20	F	R	No	1,000	696.1	18.50	20.7	20.25	22.45
Mecom, John W	7	7/9/58	Sunrise	Terrebonne	20	W	R	Yes	1,050	44.4	20.00	21.5	22.05	23.55
* Petroleum, Inc. (Op.), et al.	14*	12/23/58	Houma	Terrebonne	20	F	R	Yes	1,000	222.1*	18.50	20.7	20.25	22.45
Placid Oil Co.	20	2/5/59	Lapeyrouse	Terrebonne	18	F	None	No	1,200	1,511.7	18.50	20.8	20.25	22.55
Prentice, Robert B., et al.	2	5/14/59	Hollywood	Terrebonne	20	F	R	Yes	1,150	1,725.9	18.50	20.7	20.25	22.45
* Prentice, Robert B. (Op.), et al.	3*	5/14/59	Houma	Terrebonne	20	F	None	No	1,100	996.1	21.50	25.9	23.25*	27.45
Prentice, Robert B. (Op.), et al.	4	10/28/58	Hollywood	Terrebonne	20	F	R	No	1,150	928.8	18.50	20.7	20.25	22.45
* Shell Oil Co. (Op.), et al.	202*	5/1/59	Gibson	Terrebonne	20	F	R	Yes	1,000	6,137.3	21.25	22.8	23.30*	24.85
* Shell Oil Co.	204*	4/30/59	S. Houma	Terrebonne	20	F	R	Yes	1,200	1,890.1	21.50	23.0	23.55*	25.05
* Shell Oil Co.	205*	4/30/59	Turtle Bayou	Terrebonne	20	F	R	Yes	1,000	24,474.9	21.50	23.0	23.55*	25.05
Shell Oil Co.	214	5/1/59	N. Turtle Bayou	Terrebonne	20	F	R	Yes	1,000	4,172.7	21.50	23.0	23.55	25.05
Shell Oil Co.	219	6/29/59	Bayou Chauvin	Terrebonne	20	F	R	Yes	1,000	360.0	21.50	23.0	23.55	25.05
Shell Oil Co.	223	6/29/59	Chauvin	Terrebonne	20	F	R	Yes	1,000	360.0	21.50	23.0	23.55	25.05
Superior Oil Co., The	81	12/9/58	Sunrise	Terrebonne	20	F	R	Yes	1,050	2,555.9	20.00	21.5	22.05	23.55
* Superior Oil Co., The	89	9/8/58	Bayou Penchant*	Terrebonne	20	F	R	Yes	1,200	20,347.8	21.50	25.7	23.80	28.00
Texaco Inc.	189	10/20/58	Lapeyrouse	Terrebonne	19	F	None	No	1,200	78.8	18.50	20.8	20.25	22.55
* Texas Gulf Producing Co.	31*	1/12/59	De Large	Terrebonne	22	F	R.	Yes	1,200	1,517.1	20.00	21.6	22.05*	23.65
* Texas Gulf Producing Co.	32*	1/12/59	Dulac	Terrebonne	22	F	R	Yes	1,200	507.8	20.00	21.6	22.05*	23.65
Trahan, J. C., Drilling Contractor, Inc. (Op.) et al.	7	3/9/59	N. Turtle Bayou	Terrebonne	20	F	R	Yes	1,000	1,107.9	21.50	23.0	23.55	25.05
Trice Production Co. (Op.), et al.	10	12/10/58	Lake Hatch	Terrebonne	20	F	R	Yes	1,200	303.0	20.00	21.6	22.05	23.65
Trice Production Co.	12	6/16/59	Sunrise	Terrebonne	20	F	R	Yes	1,050	192.0	20.00	21.5	22.05	23.55
* Union Producing Co.*	228*	12/12/58	De Large	Terrebonne	20	F	R	Yes	1,200	1,517.0	20.00	21.5	22.05*	23.55
* Union Producing Co.*	229*	12/12/58	Dulac	Terrebonne	20	F	R	Yes	1,200	507.8	20.00	21.5	22.05*	23.55
* Union Producing Co.*	239*	11/4/58*	Hollywood	Terrebonne	20	F	R	Yes	1,150	811.2	18.50*	20.6*	20.25	22.35

Footnotes appear on pages 16 and 17.

FA-4606

Purchaser / Filing Company (a)	Rate Sch No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (c/Mcf) (15.025) (l)	Average Base Price (c/Mcf) (15.025) (m)	Initial Base Price Plus Tax (c/Mcf) (15.025) (n)	Average Base Price Plus Tax (c/Mcf) (15.025) (o)
HOPE NATURAL GAS COMPANY														
Amerada Petroleum Corp.	84	11/7/58	Abbeville	Vermilion	20	F	R	Yes	1,100	270.0	21.00	23.0	23.05	25.05
Amerada Petroleum Corp.	85	11/7/58	Perry	Vermilion	20	F	R	Yes	1,100	360.0	21.50	23.5	23.55	25.55
Beck Oil Co., et al.	G-17402	11/26/58	Perry	Vermilion	20	F	NR	NR	NR	NR	21.50	23.5	23.55	25.55
Texas Gas Exploration Corp. (Op.), et al.	3	12/4/58	Perry	Vermilion	20	F	R	Yes	1,100	1,345.2	21.50	23.5	23.55	25.55
Tidewater Oil Co.	92	11/10/58	Perry	Vermilion	20	F	R	Yes	1,100	283.2	21.50	23.5	23.55	25.55
TRANSCONTINENTAL GAS PIPE LINE CORPORATION														
Huffington, Roy M., Inc. (Op.), et al.	1	5/18/59	S. Intracoastal City	Vermilion	20	F	None	Yes	1,000	856.4	21.00	25.0	22.80	26.80
McDermott, J. Ray & Co., Inc. (Op.), et al.	4	11/11/58	Bancker	Vermilion	20	F	None	Yes	1,000	451.3	17.00	18.5	19.05	20.55
Pure Oil Co., The	39	1/16/58	Vermilion Area	Vermilion (Offshore)	22	W	None	Yes	1,000	1,238.7	21.40	25.8	21.40	25.80
Superior Oil Co., The	78	9/17/58	Vermilion Area	Vermilion (Offshore)	22	W	None	Yes	1,200	9,583.4	21.40	25.9	21.40	25.90
Texaco Seaboard, Inc.	27	1/15/59	Bancker	Vermilion	20	F	None	Yes	1,000	48.1	17.00	18.5	19.05	20.55
Trice Production Co. (Op.), et al.	11	12/23/58	Bancker	Vermilion	20	F	None	Yes	1,000	459.9	17.00	18.5	19.05	20.55
Zapata Off-Shore Co. (Op.), et al.	1	4/7/59	Block 86, Vermilion Area	Vermilion (Offshore)	22	W	None	Yes	1,200	1,819.8	21.40	26.1	21.40	26.10
TRUNKLINE GAS COMPANY														
Austral Oil Co., Inc.	13	7/18/58	N. Freshwater Bayou	Vermilion	22	F	None	Yes	1,200	857.0	22.00	26.3	24.05	28.35
Nicklos Oil & Gas Co. (Op.), et al.	2	8/20/58	S.W. Esther	Vermilion	22	F	None	Yes	1,000	4,642.7	22.00	26.3	24.05	28.35
* Pan American Petroleum Corp.	258	6/26/58	Block 14, Vermilion Area*	Vermilion (Offshore)	22	W	None	Yes	1,200	6,458.3	22.00	26.3	24.05	28.35
Pan American Petroleum Corp.	259	9/2/58	Kaplan	Vermilion	22	W	None	Yes	1,200	726.1	22.00	26.3	24.05	28.35
Pan American Petroleum Corp.	260	9/2/58	N. Freshwater Bayou	Vermilion	22	W	None	Yes	1,200	857.0	22.00	26.3	24.05	28.35
Union Oil Co. of California	40	6/17/58	N. Freshwater Bayou	Vermilion	23	F	None	Yes	1,200	6,816.2	22.00	26.3	24.05	28.35
Union Oil Co. of California	42	6/17/58	Block 26, Vermilion Area	Vermilion (Offshore)	23	W	None	Yes	1,200	5,036.6	22.00	26.3	22.00	26.30
UNITED FUEL GAS COMPANY														
Humble Oil & Refining Co.	135	4/8/58	Florence	Vermilion	20	F	FN,R	Yes	1,000	2,536.6	17.20	20.2	18.70	21.70
* MPS Production Co., Inc., et al.	1*	7/17/58	Erath	Vermilion	*	F	R	Yes	1,000	471.7*	20.60	22.7	22.10	24.20
Pan American Petroleum Corp.	219	1/9/58	Erath	Vermilion	21	F	R	Yes	1,000	1,295.1	20.60	22.6	22.10	24.10
Pan American Petroleum Corp.	240	10/2/58	Florence	Vermilion	20	F	R	Yes	1,000	784.4	17.60	20.2	19.10	21.70

Footnotes appear on page 17.

Purchaser / Filing Company (a)	Rate Sch. No. (or Docket Number) (b)	Date of Contract (c)	Field (d)	Parish (e)	Term (Yrs) (f)	Pt. of Del. (g)	Price Adjustment Clause (h)	Take or Pay (i)	Maximum Delivery Pressure (j)	Annual Volume (MMcf) (15.025) (k)	Initial Base Price (¢/Mcf) (15.025) (l)	Average Base Price (¢/Mcf) (15.025) (m)	Initial Base Price Plus Tax (¢/Mcf) (15.025) (n)	Average Base Price Plus Tax (¢/Mcf) (15.025) (o)
UNITED GAS PIPE LINE COMPANY														
Kellerman, R. E.	1	10/15/58	Theall	Vermilion	20	F	R	No	1,025	105.0	18.50	20.7	20.25	22.45
McLean, Harvey	1	7/10/58	Theall	Vermilion	20	F	R	No	1,025	33.6	18.50	20.5	20.25	22.25
Sinclair Oil & Gas Co.	172	1/29/59	N. Leroy	Vermilion	20	F	R	Yes	1,025	540.0	20.50	22.2	22.25	23.95
Superior Oil Co., The	79	9/24/58	Theall	Vermilion	20	F	R	No	1,025	473.1	18.50	20.7	20.25	22.45
Texas Gulf Producing Co.	30	3/14/58	Abbeville	Vermilion	20	F	R	No	1,000	221.5	18.50	20.8	20.25	22.55
COASTAL TRANSMISSION CORPORATION														
Helis Petroleum Corp. (Op.), et al.	1	1/9/59	Port Allen	W. Baton Rouge	20	F	FN,R	Yes	1,000	180.0	18.00	19.8	19.75	21.55

3782

Source

This schedule includes contracts filed with the Federal Power Commission as rate schedules which cover the sale of natural gas to interstate pipelines in South Louisiana, are dated between January 1, 1958 and June 30, 1959, have a term of 15 years or longer (or life of reserves), and microfilmed by the C. D. Lockwood Company through June 30, 1961; Additional contracts filed as exhibits in certificate applications through September 1961 have also been included.

For the purpose of this exhibit, "South Louisiana" includes all parishes, including offshore areas, lying on or south of 31° North Latitude.

Contracts are arranged by parish and within parish by purchaser. The filing companies making sales from a particular parish to a particular purchaser are listed alphabetically.

Column Headings

In general the column headings are self-explanatory.

Column (a) shows the names of the purchaser and the company filing the contract with the Federal Power Commission.

Column (b) shows the filing company's rate schedule number. Where other filing companies have been identified as making sales under the contract, this is noted by a footnote. Where the given rate schedule supersedes an earlier contract previously filed as a rate schedule, the superseded rate schedule is identified in a footnote.

Column (c) shows the date of contract except that, in cases in which the price schedule has been revised by an amendment to the contract, the date of the amendment is shown. Such cases are identified by footnotes. If a contract ratifies a contract filed by another company, the date shown is the date of the ratification and the contract being ratified is identified by a footnote.

Under "Term of Contract," "Life" means life of reserves or plant, and a number, i.e. "20", shows the number of years for which the contract is written.

In column (g), showing point of delivery, "W" means wellhead or separator, "F" means a designated place in the field, "P" means a delivery of residue gas at the outlet of a plant, and "O" means a delivery point outside the field.

(3782)

Column (h), headed "Price Adjustment Clause," shows whether the contract contains a clause which attempts to provide in whole or in part for adjustments in price in light of market conditions at the time of delivery. "FN" refers to a favored-nation clause which is operative throughout the life of the contract, "O" refers to any other type of adjustment clause which is operative throughout the life of the contract, and "R" refers to a clause which provides for redetermination of the price only after a specified period of years. One contract may contain clauses of more than one type.

In column (i), headed "Take or Pay", "Yes" means that there is provision in the contract for guarantee payment for a specified volume of gas, and "No" means that no provision for such payment is included in the cotract.

"Maximum Delivery Pressure" is the maximum pressure (in psig) at which the seller may have to make deliveries in order for the gas to enter the buyer's line. Where there is no specification in the contract or where the specification merely states a pressure sufficient to enter the buyer's line, a dash (—) is used in this column.

Column (k) shows 1960 volumes obtained from Form 2 reports of pipelines filed with the Federal Power Commission. For contracts where no 1960 deliveries were made, volume is based on estimated first-month deliveries as reported by producers at the time the contract was filed.

The "Initial Base Price" (column (l)) is as shown in the base price schedule as applicable at the date of the contract shown in column (c) (or at the date of an amendment revising the price schedule where this is the date shown in column (c)). Accordingly, this price includes no adjustment for tax reimbursement or for other reasons.

The "Average Base Price" (column (m)) is an average of the separate prices specified in the contract base price schedule over the duration of the contract. Each contract price is weighted by the number of months it is scheduled to be effective. Where the term of the contract is "Life", a 20-year period is used in computing the average price.

3783

Columns (n) and (o) show initial and average base prices plus tax reimbursement payable based on the severance tax charged by the State of Louisiana. The tax reimbursement shown is that to

which the seller has been entitled since December 1, 1958 under the terms of his contract as filed with the Federal Power Commission.

Footnotes

Footnotes appear at page 14, and are designated by an asterisk shown at the left of the given line.

Throughout the listing "NR" means not reported or not identified.

3784

Footnotes for South Louisiana

Tidewater Oil Co. Rate Schedule No. 91: This contract covers acreage in Acadia and Lafayette parishes.

Midwest Oil Corp. (Op.), et al. Rate Schedule No. 20. This contract ratifies a 20-year contract dated 12/30/52 between Sun Oil Co. and the buyer, filed as Sun Oil Co. Rate Schedule No. 38.

Reese E. Carter (Op.), et al. Rate Schedule No. 1: This contract covers deliveries from Maxie and Ellis fields.

H. L. Hunt Rate Schedule No. 18: This contract ratifies a 20-year contract dated 4/9/57 between Bel Oil Corp. and the buyer, filed as Bel Oil Corp. Rate Schedule No. 5, Sales under this rate schedule are also made by Lyda Bunker Hunt Estate (Rate Schedule No. 7) and Secure Trusts (Rate Schedule No. 5). Volume shown is the total volume reported for this contract.

This contract covers deliveries from N. Elton and Oberlin fields.

H. L. Hunt, et al. Rate Schedule No. 25: Date shown is the date of an amendment to a contract dated 9/18/58, which ratifies Shell Oil Co. Rate Schedule No. 25, a 20-year contract dated 8/31/54. The term was extended to 6/1/79 by the amendment, and the prices shown are from the contract as amended. The inerease in price from 16.00¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimursement was suspended until 4/8/60 by FPC order issued 11/6/59 in Docket No. G-20071.

F. E. Jameson, et al. Rate Schedule No. 2: This contract was filed to supersede F. E. Jameson, et al. Rate Schedule No. 1. The new contract was written because of the operation of the

favored-nation clause in the original contract. The increase in price from 16.00¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/11/59 by FPC order issued 6/4/59 in Docket No. G-18672.

Mound Company, et al. Rate Schedule No. 15: This contract ratifies a 20-year contract dated 12/29/55 between Sun Oil Co. and the buyer, filed as Sun Oil Co. Rate Schedule No. 71.

Shell Oil Co. Rate Schedule No. 198: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 25. The increase in price from 16.00¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 10/16/59 by FPC Order issued 5/14/59 in Docket No. G-18469.

C. H. Lyons, Jr., et al Rate Schedule No. 4: This contract ratifies a 20-year contract dated 7/11/56 between Texas Gulf Producing Co., et al. and buyer, filed as Texas Gulf Producing Co. Rate Schedule No. 23.

Union Oil Co. of Calfornia Rate Schedule No. 30: This contract was filed to supersede Union Oil Co. of California Rate Schedule No. 8, a short-term contract dated 1/25/46 which expired by its own terms. The increase in price from 9.00¢/Mcf plus tax reimbursement to 18.50¢/Mcf plus 1.75¢/Mcf tax reimbursement was suspended until 12/26/59 by FPC order issued 7/22/59 in Docket No. G-19006.

General Crude Oil Co. Rate Schedule No. 7: Sales under this contract also made by Hurt Oil and Gas Corp., et al. (Rate Schedule No. 1) Volume shown is the total volume reported for the contract.

This contract covers acreage in Calcasieu and Beauregard parishes.

Gulf Oil Corp. (Op.), et al. Rate Schedule No. 161: This contract was filed to supersede Gulf Oil Corp. Rate Schedule No. 85. The increase in price from 12.3142¢/Mcf plus tax reimbursement to 20.50¢/Mcf plus 2.3¢/Mcf tax reimbursement was suspended until 11/7/59 by FPC order issued 6/4/59 in Docket No. G-18669.

This contract covers acreage in Calcasieu and Jefferson Davis Parishes.

Shell Oil Co. (Op.) Rate Schedule No. 203: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 51. The increase in price from 8.997¢/Mcf plus tax reimbursement to 18.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended

until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18698.

This covers acreage in Calcasieu and Jefferson Davis parishes.

Phillips Petroleum Co., et al. Rate Schedule No. 355: Sales under this contract also made by Kerr-McGee Oil Industries, Inc. (Rate Schedule No. 64) and J. Ray McDermott and Co., Inc. (Rate Schedule No. 12). Volume shown is the total volume reported for this contract.

Caroline Hunt Sands, et al. Rate Schedule No. 5: This contract covers acreage in Cameron and Jefferson Davis parishes.

Amerada Petroleum Corp. Rate Schedule No. 82: This contract covers acreage in Iberia and St. Martin parishes.

3785

Phillips Petroleum Co. Rate Schedule No. 372: This contract covers acreage in Iberia and St. Martin parishes.

Sid W. Richardson, et al. d/b/a Richardson & Bass (Op.), et al. Rate Schedule No. 2: This contract covers deliveries from Jefferson Island, Abbeville, Maxie, South Rayne and Woodlawn fields in Iberia, Acadia, Jefferson Davis, Lafayette and Vermilion parishes.

The California Co., Rate Schedule No. 13: This contract supersedes The California Co. Rate Schedule No. 9 only as to certain acreage not previously producing.

Continental Oil Co. Rate Schedule No. 172: This contract ratifies a 20-year contract dated 8/7/57 between The California Co. and the buyer, filed as The California Co. Rate Schedule No. 7. This contract covers acreage in Iberia and St. Martin parishes.

Shell Oil Co. (Op.), et al. Rate Schedule No. 206: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 58. The increase in price from 8.997¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18697.

This contract covers acreage in Iberia and St. Martin parishes.

Bel Oil Corp. Rate Schedule No. 7: This contract covers acreage in Jefferson Davis and Cameron parishes.

Homer T. Moore Rate Schedule No. 1: Tax reimbursement is based on pressure and volume. If production of gas from a well is 250 Mcf/day or more, tax reimbursement will be 1.75¢/Mcf; if production is less than 250 Mcf/day, tax reimbursement will be 0.875¢/Mcf.

Gulf Oil Corp. Rate Schedule No. 163: This contract ratifies a life contract dated 8/31/56 bewteen J. P. Owen (Op.), et al. and the buyer, filed as J. P. Owen (Op.), et al. Rate Schedule No. 2.

Tidewater Oil Co. Rate Schedule No. 85: This contract ratifies a life contract dated 8/31/56 between J. P. Owen (Op.), et al. and the buyer filed as J. P. Owen (Op.), et al. Rate Schedule No. 2.

Crown Central Petroleum Corp. Rate Schelule No. 7: This contract covers acreage in Lafayette and Vermilion parishes.

Monsanto Chemical Co. (Op.), et al. Rate Schedule No. 28: This contract covers acreage in Lafayette and St. Martin parishes.

Tidewater Oil Co. Rate Schedule No. 75: This contract covers acreage in Lafayette and Vermilion parishes.

H. L. Hunt Rate Schedule No. 30: All prices subject to 1.00¢/Mcf payment for gathering, payable at all times.

Sinclair Oil and Gas Co. (Op.), et al. Rate Schedule No. 167: This contract covers acreage in Lafourche and Terrebonne parishes.

Sohio Petroleum Co. Rate Schedule No. 50: This contract ratifies a 20-year contract dated 7/17/58 between Sinclair Oil & Gas Co. and the buyer, filed as Sinclair Oil & Gas Co. Rate Schedule No. 167.

Cities Service Production Co. (Op.), et al. Rate Schedule No. 7: Sales under this contract were made by Phillips Petroleum Co. (Rate Schedule No. 334). Phillips Petroleum Co. Rate Schedule No. 334 was withdrawn on 5/20/60.

This contract covers acreage in Lafourche and St. James Parishes.

Hunt Oil Co. Rate Schedule No. 50: This contract ratifies at 21-year contract dated 7/29/57 between Pan American Petroleum Corp. and the buyer, filed as Pan American Petroleum Corp. Rate Schedule No. 204.

Sword Co., et al. Rate Schedule No. 1: This contract ratifies a 21-year contract dated 8/15/57 between Pan American Petroleum Corp. and the buyer, filed as Pan American Petroleum Corp. Rate Schedule No. 206.

Pan American Petroleum Corp. Rate Schedule No. 227: This contract covers acreage in Lafourche and Terrebonne parishes.

Republic Natural Gas Co., et al. Rate Schedule No. 31: This contract covers acreage in St. Charles and St. John the Baptist parishes.

Humble Oil and Refining Co. Rate Schedule No. 136: This contract covers deliveries from American Island and North American Island fields.

3786

Shell Oil Co. (Op.), et al. Rate Schedule No. 207: This contract was filed to supersede Shell Oil Company Rate Schedule No. 59. The increase in price from 8.997¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18697.

Shell Oil Co. Rate Schedule No. 220: This contract covers acreage in St. Mary and Terrebonne parishes.

Southwest Gas Producing Co., Inc. (Op.), et al. Rate Schedule No. 12: Sales under this contract are also made by Argo Oil Corp. (Rate Schedule No. 37). Volume shown is the total volume reported for this contract.

Humble Oil & Refining Co. Rate Schedule No. 148: Sales under this contract are also made by Lillie C. Cullen, et al. (Rate Schedule No. 2). Volume shown is the total volume reported for this contract.

Hassie Hunt Trust Rate Schedule No. 22: Sales under this contract are also made by The British-American Oil Producing Co. (Rate Schedule No. 42). Volume shown is the total volume reported for this contract.

This contract covers deliveries from Northwest Mosquito Bay and Wildcat Bayou fields.

Shell Oil Co. Rate Schedule No. 200: This contract covers deliveries from Humphreys and S. Humphreys fields.

Petroleum, Inc. (Op.), et al. Rate Schedule No. 14: Sales under this contract also made by Hurt Oil & Gas Corp. Rate Schedule No. 3. Volume shown is the total volume reported for this contract.

Robert B. Prentice (Op.), et al. Rate Schedule No. 3: This contract was filed to supersede Robert B. Prentice (Op.), et al. Rate Schedule No. 1, a 10-year contract dated 3/13/50. The increase in price from 10.00¢/Mcf plus tax reimbursement to 21.50¢/Mcf plus 1.75¢/Mcf tax reimbursement was suspended until 3/1/60 by FPC order issued 9/18/59 in Docket No. G-19475.

Shell Oil Co. (Op.), et al. Rate Schedule No. 202: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 50, a short-term contract dated 10/5/44. The increase in price from 8.997¢/Mcf plus tax reimbursement to 21.25¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18697.

Shell Oil Co. Rate Schedule No. 204: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 54. The increase in price from 8.997/Mcf plus tax reimbursement to 21.50¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18699.

Shell Oil Co. Rate Schedule No. 205: This contract was filed to supersede Shell Oil Co. Rate Schedule No. 56. The increase in price from 8.997¢/Mcf plus tax reimbursement to 21.50/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 11/13/59 by FPC order issued 6/11/59 in Docket No. G-18699.

The Superior Oil Co. Rate Schedule No. 89: This contract covers deliveries from Bayou Penchant, Palmetto Bayou and Four Isle Dome fields.

Texas Gulf Producing Co. Rate Schedule No. 31: This contract was filed to supersede Texas Gulf Producing Company Rate Schedule No. 14. The increase in price from 8.997¢/Mcf plus tax reimbursement to 20.00¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 7/26/59 by FPC order issued 2/25/59 in Docket No. G-17884.

Texas Gulf Producing Co. Rate Schedule No. 32: This contract was filed to supersede Texas Gulf Producing Company Rate Schedule No. 5. The increase in price from 8.997¢/Mcf plus tax reimbursement to 20.00¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 7/28/59 by FPC order issued 2/25/59 in Docket No. G-17884.

Union Producing Company Rate Schedule No. 228: This contract was filed to supersede Union Producing Company Rate Schedule No. 68. The increase in price from 8.997¢/Mcf plus tax reimbursement to 20.00¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 6/24/59 by FPC order issued 1/22/59 in Docket No. G-17589.

Buyer and seller are associated companies.

Union Producing Company Rate Schedule No. 229: This contract was filed to supersede Union Producing Company Rate Schedule No. 69. The increase in price from 8.997¢/Mcf plus tax reimbursement to 20.00¢/Mcf plus 2.05¢/Mcf tax reimbursement was suspended until 6/24/59 by FPC order issued 1/22/59 in Docket No. G-17589.

Buyer and seller are associated companies.

3787

Union Producing Company Rate Schedule No. 239: Date Shown is the date of an amendment to a short-term contract dated 4/8/55. The term was extended by the amendment to 10/1/78. The initial and average base prices are from the contract as amended.

Buyer and seller are associated companies.

Pan American Petroleum Corp. Rate Schedule No. 258: This contract covers deliveries from Blocks 14, 15 and 26 Vermilion Area (offshore).

M?S Production Co., Inc., et al. Rate Schedule No. 1: This contract ratifies a 21-year contract dated 1/9/58 between Pan American Petroleum Corp. and the buyer, filed as Pan American Petroleum Corp. Rate Schedule No. 219.

SUMMARY OF QUALITY SPECIFICATIONS IN LONG-TERM CONTRACTS IN SOUTH LOUISIANA, CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION DATED BETWEEN JANUARY 1, 1958 AND JUNE 30, 1959

A. Btu Content of Gas

Number of Contracts In Analysis	No Minimum Specified	Minimum Btu Content per Cubic Foot a/				Credit for Excess Btu Content		Penalty for Low Btu Content	
		Below 950	950 to 974	975 to 1025	Above 1025	Proportional	Other Basis	Proportional	Other Basis
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
210	--	7	5	198	--	--	--	171	--

B. Sulfur Content

Number of Contracts In Analysis	No Limit Specified	Hydrogen Sulfide Limit (gr/100 cf)				Sulfur Limit (gr/100 cf)			Penalty for Sour Gas (Cents/Mcf)			
		0.5 or Below	0.51 to 1.0	1.1 to 5.0	Over 5.0	10.0 or Below	10.1 to 20.0	Over 20.0	0.5 or Below	0.51 to 1.0	Over 1.0	Cost to Buyer
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
210	--	53	155	2	--	41	169	--	--	--	--	26

C. Dehydration

Number of Contracts In Analysis	No Minimum Specified	Seller Dehydrates to (#/MMcf)				Payment by Purchaser (Cents/Mcf)			Payment by Seller (Cents/Mcf)			
		6.0 or Below	6.1 to 7.0	Over 7.0	Buyer's Specifications	Below .20¢	.20¢ to .25¢	Over .25¢	Below .20¢	.20¢ to .25¢	Over .25¢	Cost to Buyer
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
210	5	77	128	--	--	--	--	--	--	--	--	18

D. Delivery Pressure

Number of Contracts In Analysis	No Maximum Specified b/	Maximum Delivery Pressure (psig)							Charge of Penalty for First Stage of Compression (Cents/Mcf)			
		75 or Below	76 to 200	201 to 499	500 to 599	600 to 800	801 to 1100	Above 1100	.50¢ or Below	.51¢ to .90¢	Above .90¢	Compression Cost
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
210	--	--	--	--	--	2	183	25	--	1	2	15

Source: Data include sales to pipeline companies under contracts dated between January 1, 1958 and June 30, 1959 with terms of 15 years or longer which were filed with the FPC as rate schedules and filmed by The C. D. Lockwood Co. through June 30, 1961.

a/The minimum Btu content acceptable without penalty, or, where there is no price penalty, the minimum below which the gas may be rejected by the purchaser. Btu content is specified per cubic foot at approximately 14.73 psia.

b/Includes contracts which specify only that gas must be delivered at a pressure sufficient to enter buyer's line.

3789

Sheet 1 of 2
Schedule 3

DISTRIBUTION OF INITIAL BASE PRICES PLUS TAX REIMBURSEMENT IN SOUTH LOUISIANA UNDER LONG-TERM CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION

Contracts Dated Between January 1, 1958 and June 30, 1959

Initial Base Price Plus Tax Reimbursement (15.025 psia) (15.015 psia)	Number of Contracts Total Total	Reported Reported	Annual Volume 15.025 psia) 15,025 psia)
(a)	(b)	(c)	(d)
24.05	8	7	21,171.3
23.80	3	3	42,294.3
23.68	4	4	1,623.2
23.60	9	9	24,462.0
23.55	57	55	127,712.9
23.30	7	7	15,389.6
23.25	1	1	996.1
23.15	1	1	15,783.2
23.05	6	6	3,858.2
23.00	1	—	—
22.95	2	2	330.4
22.90	3	3	3,601.2
22.80	3	3	11,460.3
22.55	1	1	6,558.8
22.30	1	1	6,100.8
22.25	3	3	726.0
22.18	2	2	2,412.0
22.10	2	2	1,766,8
22.05	10	10	8,226.1
22.00	5	5	28,147.7

21.75	1	1	193.5
21.40	3	3	12,641.9
21.30	1	1	1,800.0
20.75	3	3	5,628.5
20.55	1	1	7,568.0
20.50	1	1	309.1
20.38	4	4	1,996.7
20.25	22	22	15,188.4
20.00	3	3	1,125.4
19.75	7	7	10,142.2
19.50	2	2	190.4
19.10	7	7	11,938.0

DISTRIBUTION OF INITIAL BASE PRICES
(continued)

Initial Base Price Plus Tax Reimbursement (Cents per Mcf) (15.025 psia)	Number of Contracts		Annual Volume (MMcf at 15.025 psia)
	Total	With Volume Reported	
(a)	(b)	(c)	(d)
19.05	3	3	959.3
18.75	4	4	1,058.2
18.70	2	2	2,896.6
18.50	8	8	3,762.1
18.10	2	2	1,246.9
17.90	5	5	1,349.0
17.75	1	1	438.1
17.50	4	4	663.7
16.00	1	1	221.4
15.50	1	1	282.0
13.75	1	1	12.0
TOTAL	216	212	404,232.3

Source: Schedule No. 1.

Schedule 4
Sheet 1 of 3

DISTRIBUTION OF AVERAGE BASE PRICES PLUS TAX REIMBURSEMENT IN SOUTH LOUISIANA UNDER LONG-TERM CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION

Contracts Dated Between January 1, 1958 and June 30, 1959

Average Base Price Plus Tax Reimbursement (Cents per Mcf) (15.025 psia)	Number of Contracts Total	Number of Contracts With Volume Reported	Annual Volume (MMcf at 15.025 psia)
(a)	(b)	(c)	(d)
28.45	2	1	744.0
28.40	1	1	14,630.4
28.35	6	6	20,427.3
28.25	1	1	281.9
28.05	2	2	2,455.0
28.00	2	2	20,983.7
27.95	8	8	7,961.1
27.88	1	1	45.3
27.85	8	8	7,280.7
27.80	1	1	82.4
27.75	1	1	619.9
27.70	1	1	7,316.1
27.68	3	3	1,577.9
27.55	5	5	10,910.8
27.50	2	2	3,330.0
27.45	1	1	996.1
27.40	7	7	14,118.4
27.35	1	1	1,080.0
27.30	4	4	15,547.6
27.05	1	1	15,783.2

(3791)

27.00	1	—	—
26.80	2	2	3,377.6
26.60	3	3	6,868.9
26.55	1	1	6,558.8
26.48	2	2	2,412.0
26.40	2	2	18,000.0
26.30	2	2	10,057.7
26.10	2	2	7,920.6
25.90	1	1	9,583.4
25.80	1	1	1,238.7
25.55	21	19	38,760.0
25.45	1	1	193.5
25.25	1	1	640.8

3792

Schedule 4
Sheet 2 of 3

DISTRIBUTION OF AVERAGE BASE PRICES (continued)

Average Base Price Plus Tax Reimbursement (Cents per Mcf) (15.025 psia)	Number of Contracts		Annual Volume (MMcf at 15.025 psia)
	Total	With Volume Reported	
(a)	(b)	(c)	(d)
25.20	1	1	1,800.0
25.15	3	3	2,538.2
24.05	12	12	59,042.7
24.85	1	1	6,137.3
24.75	1	1	618.3
24.50	1	1	309.1
24.35	2	2	330.4
24.30	1	1	661.0
24.20	2	2	8,017.2
24.10	2	2	6,110.1

23.95	1	1	540.0
23.80	1	1	100.4
23.75	2	2	186.0
23.70	1	1	90.0
23.65	3	3	2,327.9
23.60	1	1	90.0
23.55	7	7	5,898.2
23.50	3	3	1,598.0
23.45	1	1	7,568.0
22.58	4	4	1,996.7
22.55	5	5	8,092.6
22.45	14	14	9,371.3
22.35	2	2	1,615.2
22.30	2	2	8,141.8
22.25	2	2	221.3
22.10	2	2	823.2
21.80	2	2	1,521.6
21.75	1	1	898.2
21.70	4	4	4,213.4
21.60	1	1	360.0
21.55	2	2	337.7
21.25	1	1	6.7
21.00	1	1	360.0
20.80	5	5	2,011.5
20.70	1	1	1,631.3

Schedule 4
Sheet 3 of 3

DISTRIBUTION OF AVERAGE BASE PRICES
(continued)

Average Base Price Plus Tax Reimbursement (Cents per Mcf) (15.015 psia)	Number of Contracts		Annual Volume (MMcf at 15.025 psia)
	Total	With Volume Reported	
(a)	(b)	(c)	(d)
20.55	5	5	1,638.8
20.35	1	1	17.8
20.25	1	1	372.0
20.10	3	3	1,496.7
20.00	1	1	641.5
19.90	1	1	192.0
19.80	1	1	360.0
19.70	1	1	420.0
19.65	1	1	438.1
19.50	2	2	315.6
19.40	2	2	284.4
17.50	1	1	190.9
17.00	1	1	282.0
16.00	1	1	221.4
15.65	1	1	12.0
TOTAL	216	212	404,232.3

Source: Schedule No. 1.

Schedule 5

SUMMARY OF PRICES IN SOUTH LOUISIANA UNDER LONG-TERM CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION

Contracts Dated Between January 1, 1958 and June 30, 1959

Range Based on Volume	Initial Base Price Plus Tax Reimbursement	Average Base Price Plus Tax Reimbursement
(a)	(b)	(c)
1. Highest Price	24.05	28.45
2. High 10%	23.80	28.00
3. Median	23.55	25.90
4. Low 10%	20.25	22.55
5. Lowest Price	13.75	15.65

Source: Contracts dated January 1, 1958 through June 30, 1959 which cover sales to pipeline companies, have a term of 15 years or longer (or life), were filed with the Federal Power Commission as rate schedules, and were microfilmd by The C. D. Lockwood Company through June 30, 1961; additional contracts filed as exhibits in certificate applications filed with the Federal Power Commission through September 30, 1961.

"Low 10%" indicates that contracts covering 10 per cent of the volume delivered in 1960 are at or below the price shown. "Median" is the price above and below which contracts covering half of the volume fall, and "High 10%" indicates that contracts covering 10% of the volume are at or above the price shown.

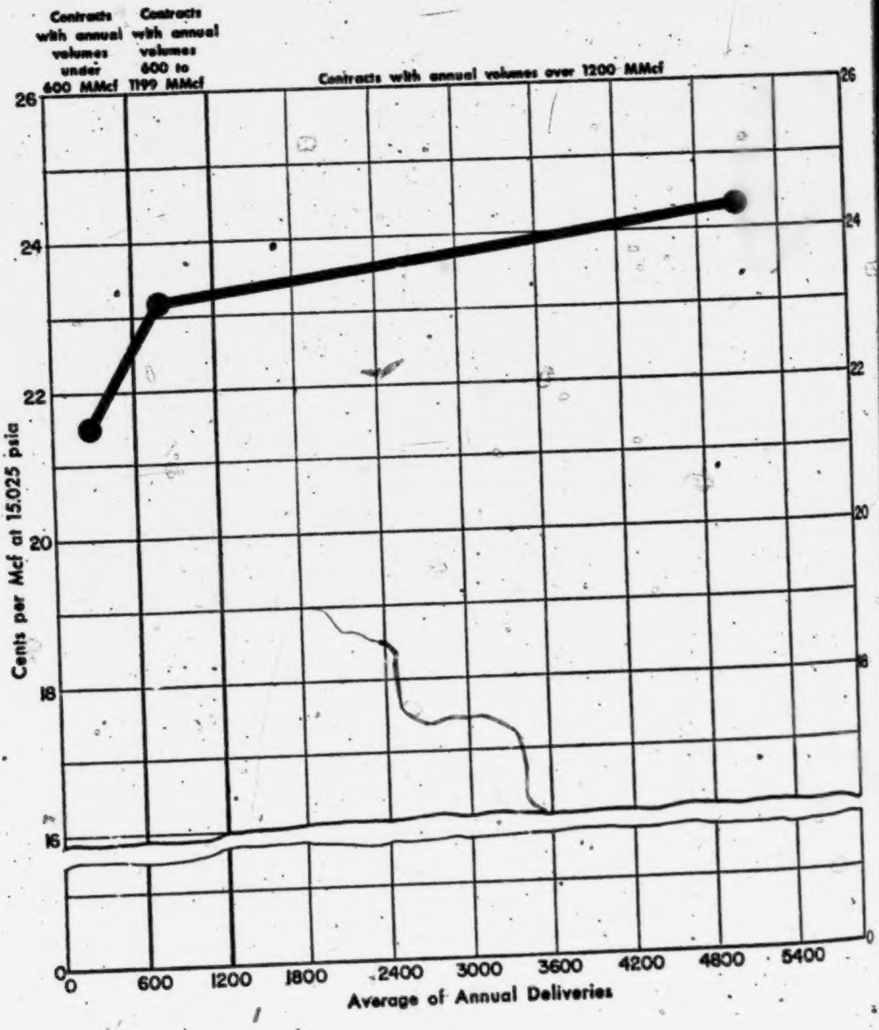
CHART 1

RELATIONSHIP BETWEEN PRICE AND VOLUME

MEDIAN AVERAGE BASE PRICES AND AVERAGE VOLUMES FOR THREE VOLUME CLASSES

SOUTH LOUISIANA

CONTRACTS DATED BETWEEN JANUARY 1, 1958 AND JUNE 30, 1959



Schedule 6

RELATIONSHIP BETWEEN PRICE AND VOLUME

Median Average Base Prices for Three Volume Classes

SOUTH LOUISIANA

Contracts Dated Between January 1, 1958 and June 30, 1959

	Volume Class		
	Under 600 MMcf	600-1199 MMcf	1200 MMcf or More
	(a)	(b)	(c)
Number of Contracts	102	41	67
Annual Deliveries (MMcf at 15.025 psia)			
Total	27,611.0	32,944.5	341,696.8
Average per Contract	270.7	803.5	5,100.0
Median Average Base Price (Cents per Mcf at 15.025 psia)	21.5c	23.2c	24.3c

Source: Contracts dated January 1, 1958 through June 30, 1959, which cover sales to pipeline companies, have a term of 15 years or longer (or life), were filed with the Federal Power Commission as rate schedules and were microfilmed by The C. D. Lockwood Company through June 30, 1961.

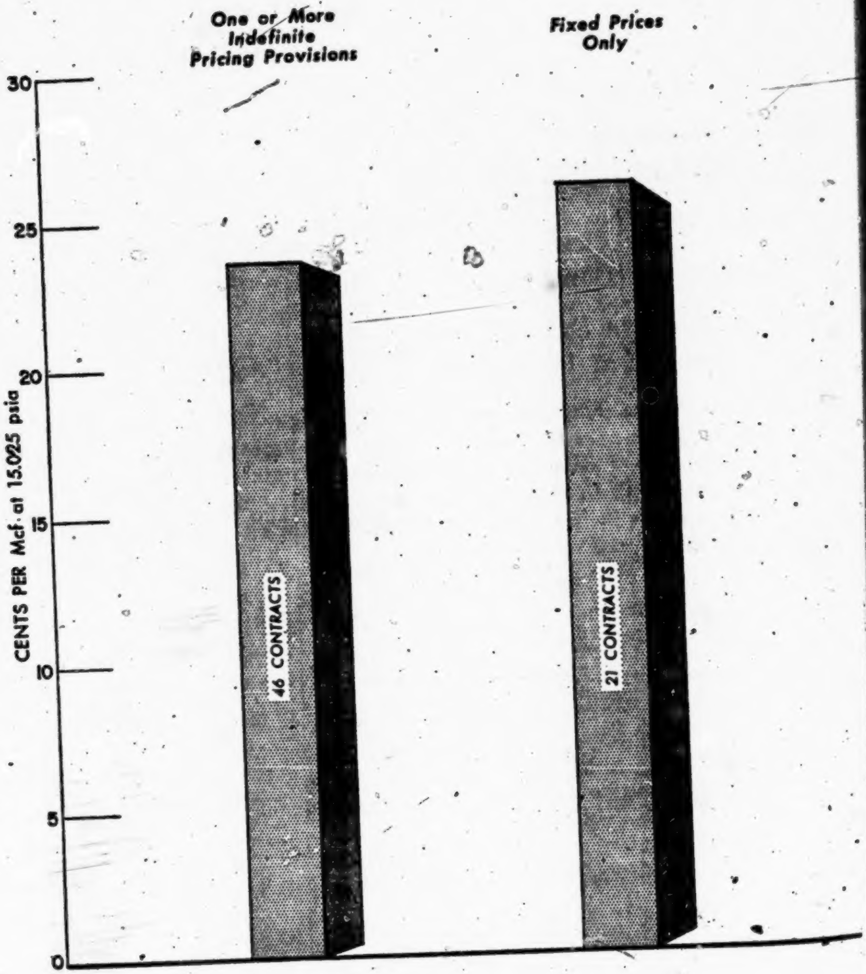
The "Median" is the price above and below which is to be found one-half the contracts within each volume class.

CHART 2

RELATIONSHIP BETWEEN PRESENCE OR ABSENCE OF INDEFINITE PRICING PROVISIONS AND AVERAGE BASE PRICES

LARGE VOLUME CONTRACTS IN SOUTH LOUISIANA
Dated Between January 1, 1958 and June 30, 1959

WEIGHTED AVERAGE OF AVERAGE BASE PRICE



Schedule 7

RELATIONSHIP BETWEEN PRESENCE OR ABSENCE OF INDEFINITE PRICING PROVISIONS AND AVERAGE BASE PRICES

Large Volume Contracts in South Louisiana Dated January 1, 1958 through June 30, 1959

Weighted Average of Average Base Prices

(1200 MMcf or More per year)

	One or More Indefinite Pricing Provisions	Fixed Prices (Only)
	(a)	(b)
Number of Contracts	46	21
Annual Deliveries (MMcf at 15.025 psia)		
Total	243,406.1	98,290.7
Average per contract	5,291.4	4,680.5
Weighted Average of Average Base Prices (Cents per Mcf at 15.025 psia)	23.6	25.9

Source: Contracts dated January 1, 1958 through June 30, 1959, which cover sales to pipeline companies, have a term of 15 years or longer (or life), were filed with the Federal Power Commission as rate schedules, and were microfilmed by The C. D. Lockwood Company through June 30, 1961.

The contracts included are those with average annual volumes of 1200 MMcf or more.

Schedule 8

SUMMARY OF PRICES IN SOUTH LOUISIANA UNDER LONG-TERM CONTRACTS FILED WITH THE FEDERAL POWER COMMISSION

Contracts Dated July 1, 1959 or Later

Range Based on Volume	Initial Base Price Plus Tax Reimbursement	Average Base Price Plus Tax Reimbursement
(a)	(b)	(c)
1. Highest Price	24.80	28.80
2. High 10%	23.60	27.90
3. Median	22.83	25.90
4. Low 10%	20.67	23.00
5. Lowest Price	12.50	14.50

Source: Contracts dated July 1, 1959 or later which cover sales to pipeline companies, have a term of 15 years or longer (or life), were filed with the Federal Power Commission as rate schedules, and were microfilmed by The C. D. Lockwood Company through June 30, 1961; additional contracts filed as exhibits in certificate applications filed with the Federal Power Commission through September 30, 1961.

"Low 10%" indicates that contracts covering 10 per cent of the estimated volume to be delivered are at or below the price shown. "Median" is the price above and below which contracts covering half of the volume fall, and "High 10%" indicates that contracts covering 10% of the volume are at or above the price shown.

3800

Hearing Ex. No. X-6, Rev. Sched. #9

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. G-12446, et al.

In the Matters of

TEXAS EASTERN TRANSMISSION CORPORATION, et al.

EXHIBIT ACCOMPANYING TESTIMONY OF JOHN P. FURMAN SCHEDULE 9 REVISED

Foster Associates, Inc.
Washington, D. C.

November 1961

FA-4633

SALES IN SOUTH LOUISIANA PERMANENTLY CERTIFICATED BY THE FEDERAL POWER COMMISSION
WITH AVERAGE BASE PRICES OF 20.00¢/Mcf OR ABOVE
BY DATE OF CERTIFICATION

Purchaser Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume[a/] (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement[b/] (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement[b/] (m)
									(Cents per Mcf at 15.025 psia)			
United Fuel Gas Company												
Tidewater Oil Co.	2801	10/28/54	26	9/11/52	Erath	Vermilion	20	8,622.9	20.00	21.50	21.9	23.40
Humble Oil & Refining Co.	3109	11/2/54	23	9/11/52	Erath	Vermilion	20	2,771.5	20.00	21.50	21.9	23.40
Texaco Inc.	3646	11/2/54	6	9/10/52	Erath	Vermilion	20	15,859.2	20.00	21.50	21.9	23.40
United Gas Pipe Line Company												
Cocke, W. H.	3059	12/13/54	1	7/26/54	Duck Lake	St. Mary, St. Martin	19	200.6	12.50	14.25	21.4	23.15
Goodrich, R. H.	3026	12/13/54	1	7/30/54	Duck Lake	St. Mary, St. Martin	19	200.6	12.50	14.25	21.4	23.15
Humble Oil & Refining Co.	3112	12/15/54	35	2/9/54	Duck Lake	St. Mary, Iberia	19	10,990.8	12.35	14.10	21.0	22.75
American Louisiana Pipe Line Company												
British American Oil Producing Co., The	6813	5/9/55	17	11/6/53	Cameron	Cameron	23	3,730.7	18.25	19.75	22.0	23.50
Kerr-McGee Oil Industries, Inc.	6068	5/9/55	27	11/6/53	Cameron	Cameron	20	3,656.7	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6069	5/9/55	152	11/1/53	Savoy	St. Landry	23	1,737.8	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6070	5/9/55	153	11/1/53	Iowa	Jefferson Davis, Calcasieu	23	4,579.6	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6071	5/9/55	154	6/1/53	Lewisburg	Acadia, St. Landry	23	1,781.3	20.00	21.50	23.8	25.30
Pan American Petroleum Corp.	6072	5/9/55	155	11/1/53	N. Elton	Allen	23	1,925.1	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6073	5/9/55	156	11/1/53	S. Elton	Jefferson Davis	23	1,099.7	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6074	5/9/55	157	11/1/53	Welsh	Jefferson Davis	23	1,822.7	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6075	5/9/55	158	11/1/53	Bayou Mallet	Acadia	23	2,192.9	18.25	19.75	22.0	23.50
Pan American Petroleum Corp.	6076	5/9/55	159	6/1/53	S. Jennings	Jefferson Davis	23	8,418.9	20.00	21.50	23.8	25.30
Pan American Petroleum Corp.	6077	5/9/55	160	11/1/53	Cameron	Cameron	23	8,361.9	18.25	19.75	22.0	23.50
Superior Oil Co., The	6067	5/9/55	7	7/17/53	W. Cameron	Cameron, Vermilion	20	60,604.3	20.00	21.50	23.8	25.30
United Gas Pipe Line Company												
Johnston, C. N., et al.	8732	6/27/55	1	4/8/55	Duck Lake	St. Mary, St. Martin	18	16.3	12.50	14.25	21.6	23.35
Texaco Inc.	4821	12/5/55	102	6/1/54	Duck Lake	St. Mary	19	1,818.2	12.50	14.25	21.2	22.95
Texas Gas Transmission Corporation												
Atlantic Refining Co., The	8809	12/30/55	155	4/22/55	E. Lake Palourde	Assumption	20	473.9	20.00	21.75	23.0	24.75
California Co., The	8810	12/30/55	5	4/1/55	E. Lake Palourde	Assumption	20	2,836.3	20.00	21.75	23.0	24.75
Union Oil Co. of California	8811	12/30/55	13	4/14/55	E. Lake Palourde	Assumption	20	21,735.0	20.00	21.875[c/]	23.0	24.875[c/]
United Fuel Gas Company												
Phillips Petroleum Co.	10020	8/10/56	273	1/21/53	Erath	Vermilion	20	16,707.9	20.00	21.50	21.9	23.40
Texas Gas Transmission Corporation												
Grande Corp., The	10669	1/18/57	2	6/26/56	Thibodaux	Lafourche	20	5,177.2	20.00	21.75	23.0	24.75

Page 30

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (Mcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement b/ (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement b/ (m)
									(Cents per Mcf at 15.025 psia)			
American Louisiana Pipe Line Company												
Phillips Petroleum Co.	10504	3/13/57	278	5/21/56	Lewisburg	Acadia, St. Landry	20	783.4	20.00	21.50	23.8	25.30
Grey Wolf Drilling Co.	10258	4/8/57	1	2/1/56	Savoy	St. Landry	23	466.1	18.25	19.75	22.0	23.50
Southern Natural Gas Company												
Kerr-McGee Oil Industries, Inc.	12235	7/12/57	51	2/26/57	Breton Sound	Plaquemines	20	d/	20.25	22.00	22.3	24.05
Kerr-McGee Oil Industries, Inc.	12234	7/12/57	52	3/1/57	Main Pass	Plaquemines	20	9,682.5	20.25	22.00	22.3	24.05
Phillips Petroleum Co.	12333	7/12/57	299	2/26/57	Bastian Bay	Plaquemines	20	5,546.8	20.25	22.00	22.3	24.05
Phillips Petroleum Co.	12334	7/12/57	300	2/26/57	Main Pass, Chandelier Sound	Plaquemines, St. Bernard	20	2,668.3	20.25	22.00	22.3	24.05
Phillips Petroleum Co.	12335	7/12/57	301	2/26/57	Breton Sound	Plaquemines	20	4,158.6	20.25	22.00	22.3	24.05
Socony Mobil Oil Co., Inc.	12362	7/12/57	164	2/27/57	Main Pass Area	Plaquemines	20	1,516.5	20.25	22.00	22.3	24.05
American Louisiana Pipe Line Company												
Trice Production Co.	12069	7/19/57	4	5/7/56	Welsh	Jefferson Davis	20	1,557.8	18.25	19.75	22.0	23.50
Texas Gas Transmission Corporation												
Superior Oil Co., The	11559	7/29/57	69	11/16/56	Amelia, E. Lake Palourde	Assumption	20	1,[illegible]56.2	20.00	21.875 m/	23.0	24.875 m/
United Fuel Gas Company												
Royalite Oil Co., Inc.	12398	8/6/57	1	3/15/57	Deep Lake	Cameron	20	503.1	16.80	18.30	20.0	21.50
Seagram, Joseph E. & Sons, Inc. d/b/a Frankfort Oil Co.	12398	8/6/57	3	3/15/57	Deep Lake	Cameron	20	503.1	16.80	18.30	20.0	21.50
American Louisiana Pipe Line Company												
Herrington, Louise H.	11590	8/8/57	2	10/15/56	S. Elton	Jefferson Davis	23	4.5	18.25	19.75	22.1	23.60
United Gas Pipe Line Company												
Humble Oil & Refining Co.	12422	10/29/57	123	3/5/57	Lapeyrouse	Terrebonne	20	2,159.4	18.50	20.25	20.7	22.45
United Fuel Gas Company												
Mosbacher, Robert	12266	11/6/57	10	10/26/56	Erath	Vermilion	20	170.2	20.20	21.70	22.3	23.80
United Gas Pipe Line Company												
Phillips Petroleum Co.	12818	12/13/57	295	5/20/57	Bayou Piquant	Terrebonne	20	--	20.00	21.75	21.5	23.25
American Louisiana Pipe Line Company												
Austral Oil Co., Inc.	11253	1/17/58	6	7/10/56	N. Holly Beach	Cameron	20	2,801.1	18.00	19.50	21.8	23.30
Seagram, Joseph E. & Sons, Inc. d/b/a Frankfort Oil Co.	11503	1/17/58	2	9/15/56	Second Bayou	Cameron	20	649.9	18.00	19.50	21.8	23.30
Tidewater Oil Co.	11265	1/17/58	61	7/10/56	N. Holly Beach	Cameron	20	1,404.8	18.00	19.50	21.8	23.30
United Fuel Gas Company												
Austral Oil Co., Inc. (Op.), et al.	12825	1/20/58	2	6/5/57	S. Lake Arthur	Cameron, Jefferson Davis, Vermilion	20	833.5	16.80	18.30	20.0	21.50
Mosbacher, Robert (Op.), et al.	12772	1/20/58	14	6/7/57	Valentine	Lafourche	20	759.2	16.80	18.30	20.0	21.50

FA-4633

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement b/ (k)	Average Base Price (k)	Average Base Price Plus Tax Reimbursement b/ (l)
									(Cents per Mcf at 15.025 psia)			
United Gas Pipe Line Company												
Humble Oil & Refining Co.	13009	1/20/58	124	7/18/57	Halter Island	Terrebonne	20	3,737.1	20.00	21.75	21.5	23.25
Austral Oil Co., Inc.	12967	1/24/58	7	7/3/57	Lake Hatch	Terrebonne	20	720.0	20.00	22.05	21.5	23.55
Superior Oil Co., The	12878	1/24/58	74	6/21/57	Lake Hatch	Terrebonne	20	278.4	20.00	22.05	21.5	23.55
Union Oil Co. of California	13003	1/24/58	21	6/25/57	Lake Hatch	Terrebonne	20	1,095.1	20.00	22.05	21.5	23.55
Tidewater Oil Co.	13136	1/27/58	66	8/15/57	S. E. Houma	Terrebonne	20	798.3	18.50	20.25	20.6	22.35
Lyons and Logan (Op.), et al.	13199	2/28/58	8	8/1/57	E. Bell City	Calcasieu	20	160.3	18.50	20.25	20.7	22.45
Trice Production Co.	13131	2/28/58	5	8/1/57	E. Bell City	Calcasieu	20	e/	18.50	20.25	20.7	22.45
Southern Natural Gas Company												
California Co., The	13947	3/17/58	8	11/15/57	W. Black Bay	Plaquemines	20	1,682.9	19.00	20.75	21.0	22.75
Continental Oil Co.	13855	3/17/58	153	9/24/57	Lake Fortuna	St. Bernard	20	46.7	19.00	20.75	21.0	22.75
Gulf Oil Corp.	13447	3/17/58	139	6/28/57	Black Bay	Plaquemines	20	4,496.4	20.25	22.00	22.3	24.05
Helis, William G., Estate of	13553	3/17/58	2	6/28/57	Lake Campo	Plaquemines	20	425.2	20.25	22.00	22.3	24.05
Helis, William G., Estate of	13554	3/17/58	3	6/28/57	Black Bay	Plaquemines	20	4,353.6	20.25	22.00	22.3	24.05
O'Meara, M. P., et al.	13339	3/17/58	2	8/23/57	Lake Fortuna	St. Bernard	20	149.2	19.00	20.75	21.0	22.75
Shell Oil Co.	13945	3/17/58	169	9/3/57	Lake Campo	Plaquemines	20	425.2	20.25	22.00	22.3	24.05
Shell Oil Co.	13944	3/17/58	176	11/19/57	W. Black Bay	Plaquemines	20	726.3	19.00	20.75	21.0	22.75
United Gas Pipe Line Company												
Ohio Oil Co., The (Op.), et al.	12185	3/25/58	36	2/1/57	Theall	Vermilion	20	1,847.0	18.50	20.25	20.7	22.45
Southern Natural Gas Company												
British-American Oil-Producing Co., The (Op.), et al.	13636	3/31/58	29	8/6/57	Tantine	Plaquemines	20	1,840.6	20.25	22.00	25.0	26.75
Cullen, Lillie C., et al.	13873	3/31/58	1	10/14/57	Tantine	Plaquemines	20	1,431.3	20.25	22.00	25.0	26.75
United Gas Pipe Line Company												
Texaco Seaboard, Inc.	11970	3/31/58	23	1/16/57	Maurice	Lafayette, Vermilion	20	1,281.2	18.50	20.25	20.7	22.45
Wrightsman, Charles B.	12055	3/31/58	3	1/16/57	Maurice	Lafayette, Vermilion	20	f/	18.50	20.00	20.7	22.20
Amerada Petroleum Corp.	14116	4/7/58	64	12/16/57	S. Lewisburg	Acadia	20	1,188.1	18.50	20.25	20.7	22.45
Southern Natural Gas Company												
Aluminum Co. of America	13290	4/18/58	1	5/16/57	NR	St. Martin	20	5,006.8	21.50	23.25	25.5	27.25
Berkshire Oil Co., et al.	13224	4/18/58	1	8/5/57	Bayou Pigeon	Iberia	20	4,200.1	21.50	23.55	25.5	27.55
California Co., The	13222	4/18/58	7	8/7/57	Bayou Long, Bayou Willars, Marreo, S. Lake Long, Tiger Ridge, W. Delta, Block 30	Iberia, St. Martin, St. Charles, Jefferson, Terrebonne, Lafourche, Plaquemines, Plaquemines (Offshore)	20	4,557.6	21.50	23.675	25.5	27.675
Continental Oil Co.	13301	4/18/58	152	7/23/57	Loisel	Iberia, St. Mary	20	559.6	21.50	23.55	25.5	27.55
Diversa, Inc.	13781	4/18/58	2	9/6/57	Bayou Pigeon	Iberia	20	234.4	21.50	23.25	25.5	27.25
Grande Corp., The	13115	4/18/58	3	7/24/57	E. Happytown, N. Bayou Bouillon	Iberville, St. Martin	20	1,354.7	21.50	23.25	25.5	27.25

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement b/ (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement b/ (m)
									(Cents per Mcf at 15.025 psia)			
Southern Natural Gas Company												
Lyons, C. H., Sr., et al.	13487	4/18/58	12	8/15/57	Bayou Long, Mystic Bayou	Iberia, St. Martin	20	3,528.2	21.50	23.25	25.5	27.25
Mecom, John W. (Op.)	13110	4/18/58	6	7/22/57	Lake Washington	Plaquemines	20	10,986.4	21.40	23.15	25.4	27.15
Shell Oil Co.	13256	4/18/58	179	6/1/57	Loisel	Iberia, St. Mary	20	2,224.0	21.50	23.55	25.5	27.55
Sohio Petroleum Co. (Op.), et al.	13135	4/18/58	46	7/8/57	Bayou Bouillon	Iberville, St. Martin	20	1,151.1	21.50	23.00	25.5	27.00
Tidewater Oil Co.	13051	4/18/58	81	7/29/57	Bayou Bouillon	St. Martin	20	635.5	21.50	23.25	25.5	27.25
United Gas Pipe Line Company												
Continental Oil Co.	12214	5/9/58	164	1/1/57	Ridge	Lafayette, Vermilion	20	2,280.9	20.50	22.25	22.0	23.75
Gulf Oil Corp.	12215	5/9/58	136	1/1/57	Ridge	Lafayette, Vermilion	20	1,150.7	20.50	22.25	22.0	23.75
Sunray Mid-Continent Oil Co.	12211	5/9/58	159	1/1/57	Ridge	Lafayette, Vermilion	20	1,670.9	20.50	22.25	22.0	23.75
Superior Oil Co., The	12121	5/9/58	71	2/5/57	Bayou Rambio	Terrebonne	20	1,551.0	20.00	22.05	21.5	23.55
Texas Gulf Producing Co.	12128	5/9/58	25	2/14/57	Bayou Rambio	Terrebonne	20	687.4	20.00	22.05	21.5	23.55
Burton, Wm. T., Industries, Inc.	12714	6/12/58	1	5/25/57	Bayou des Allemands	Lafourche, St. Charles	20	1,131.2	21.25	23.425	23.3	25.475
American Louisiana Pipe Line Company												
Socony Mobil Oil Co., Inc.	11912	6/19/58	18	7/10/56	Cameron	Cameron	20	2,889.1	18.25	20.00	22.0	23.75
United Gas Pipe Line Company												
Union Producing Co. g/	14124	8/4/58	223	12/11/57	Deer Island	Terrebonne	20	2,946.2	20.00	21.75	21.5	23.25
Texas Gas Transmission Corporation												
British-American Oil Producing Co., The	14515	8/5/58	31	11/22/57	Ramos	Assumption, St. Mary	20	2,148.9	19.00	20.75	20.7	22.45
Sohio Petroleum Co.	14569	8/5/58	43	11/22/57	Ramos	Assumption, St. Mary	20	h/	19.00	20.75	20.7	22.45
Southwest Gas Producing Co., Inc., et al.	14835	8/5/58	10	11/22/57	Ramos	Assumption, St. Mary	20	h/	19.00	20.75	20.7	22.45
United Gas Pipe Line Company												
Tidewater Oil Co.	15103	8/25/58	71	5/5/58	Midland	Acadia	20	804.0	18.50	20.25	20.6	22.35
Cities Service Co.	12852	9/5/58	25	5/13/57	Lapeyrouse	Terrebonne	20	3,483.6	18.50	20.25	20.7	22.45
McLean, Harvey	15990	9/11/58	1	7/10/58	Theall Area	Vermilion	20	33.6	18.50	20.25	20.5	22.25
American Louisiana Pipe Line Company												
Gulf Oil Corp.	10400	10/10/58	91	1/23/56	W. Little Chenier	Cameron	20	1,530.6	18.25	19.75	22.0	23.50
United Fuel Gas Company												
Hawkins, H. L. and H. L., Jr., et al.	13267	10/27/58	7	7/23/57	Valentine	Lafourche	20	136.1	16.80	18.30	20.0	21.50

Schedule 9 Revised
Sheet 5 of 10

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume[a] (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement[b] (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement[b] (m)
									(Cents per Mcf at 15.025 psia)			
United Gas Pipe Line Company												
Hawkins, H. L. & H. L., Jr., et al.	13279	10/27/58	8	9/3/57	Hayes	Jefferson Davis	20	762.7	18.50	20.25	20.7	22.45
American Louisiana Pipe Line Company												
Kerr-McGee Oil Industries, Inc.	16270	11/7/58	61	7/31/58	Big Lake	Cameron	20	661.0	18.25	19.75	22.8	24.30
Pan American Petroleum Corp.	15130	11/7/58	248	1/10/58	Big Lake	Cameron	21	7,545.5	18.25	19.75	22.7	24.20
United Gas Pipe Line Company												
Union Producing Co.[g]	13788	12/1/58	225	3/18/57	Bayou Rambio	Terrebonne	20	687.4	20.00	22.05	21.5	23.55
United Fuel Gas Company												
Sunray Mid-Continent Oil Co.	13011	12/15/58	178	5/28/57	Valentine	Lafourche	Life	185.4	16.80	18.30	20.3	21.80
Southern Natural Gas Company												
California Co., The	15262	12/29/58	9	11/8/57	Bayou Postillion	Iberia, St. Martin	20	421.7	21.50	23.675	25.5	27.675
United Gas Pipe Line Company												
Pan American Petroleum Corp.	15222	12/31/58	227	4/30/58	Bourg	Lafourche, Terrebonne	20	545.7	18.50	20.00	20.6	22.10
Pan American Petroleum Corp.	15225	1/2/59	228	4/25/58	Napoleonville	Assumption	20	277.5	18.50	20.00	20.6	22.10
Texas Gas Transmission Corporation												
California Co., The	13078	1/26/59	6	5/1/57	Simon Pass	St. Martin, St. Mary, Assumption	20	3,989.2	20.00	21.75	23.0	24.75
United Fuel Gas Company												
Shell Oil Co.	15301	1/26/59	177	5/13/58	E. Cameron	Cameron	20	7,839.6	17.60	19.10	20.8	22.30
United Gas Pipe Line Company												
Sands, Caroline Hunt	15492	2/10/59	2	6/24/58	N. W. Oberlin	Allen	20	516.4	18.50	20.375	20.7	22.575
Monsanto Chemical Co. (Op.), et al.	14874	5/12/59	28	4/1/58	Broussard	Lafayette, St. Martin	20	751.6	18.50	20.25	20.7	22.45
Trunkline Gas Company												
Nicklos Oil & Gas Co. (Op.), et al.	16222	5/22/59	2	8/20/58	S. W. Esther	Vermilion	22	4,642.7	22.00	24.05[i]	26.3	28.35[i]
Pan American Petroleum Corp.	15438	5/22/59	258	6/26/58	Blocks 14, 15, 26	Vermilion (Offshore)	22	6,458.3	22.00	24.05[i]	26.3	28.35[i]
Pan American Petroleum Corp.	16502	5/22/59	259	9/2/58	Kaplan	Vermilion	22	796.1	22.00	24.05[i]	26.3	28.35[i]
Pan American Petroleum Corp.	16501	5/22/59	260	9/2/58	N. Freshwater Bayou	Vermilion	22	857.0	22.00	24.05[i]	26.3	28.35[i]
Union Oil Co. of California	15487	5/22/59	40	6/17/58	N. Freshwater Bayou	Vermilion	23	6,816.2	22.00	24.05[i]	26.3	28.35[i]
Union Oil Co. of California	15485	5/22/59	41	6/17/58	Block 67	Cameron (Offshore)	23	5,021.1	22.00	22.00	26.3	26.30

Schedule 9 Revised
Sheet 6 of 10

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement b/ (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement b/ (m)
									(Cents per Mcf at 15.025 psia)			
Trunkline Gas Company												
Union Oil Co. of California	15486	5/22/59	42	6/17/58	Block 26	Vermilion (Offshore)	23	5,036.6	22.00	22.00	26.3	26.30
United Fuel Gas Company												
Humble Oil & Refining Co.	17105	6/4/59	145	9/24/58	Go Around Bayou	Cameron	20	339.7	17.60	19.10	20.2	21.70
Kerr-McGee Oil Industries, Inc. (Op.), et al.	16992	6/4/59	60	9/24/58	Go Around Bayou	Cameron	20	552.7	17.60	19.10	20.2	21.70
United Gas Pipe Line Company												
Freeport Oil Co.	15915	7/8/59	1	6/13/58	Sunrise	Terrebonne	20	44.4	20.00	22.05	21.5	23.55
Hunt, H. L. (Op.), et al.	15924	7/8/59	19	7/7/58	Pilgrim Church Area	Allen	20	398.4	18.50	20.375	20.7	22.575
Hunt Oil Co. (Op.), et al.	15909	7/8/59	41	7/7/58	Castor Creek Area	Allen	20	361.9	18.50	20.375	20.7	22.575
Hunt Oil Co.	16145	7/8/59	42	7/29/58	S. Mermentau Area	Acadia	20	397.3	18.50	20.25	20.7	22.45
Mecom, John W.	15916	7/8/59	7	7/9/58	Sunrise	Terrebonne	20	44.4	20.00	22.05	21.5	23.55
Bel Oil Corp., et al.	16757	7/14/59	6	8/1/58	Pilgrim Church	Allen	20	720.0	18.50	20.375	20.7	22.575
Lyons & Logan (Op.), et al.	14743	7/27/59	9	3/1/58	Gibson	Terrebonne	20	696.1	18.50	20.25	20.7	22.45
Southern Natural Gas Company												
Bateman, Earl G. d/b/a Bateman Drilling Co. (Op.), et al.	15141	8/7/59	4	4/11/58	Felice Bayou	Plaquemines	20	618.3	19.00	20.75	23.0	24.75
Hunt, H. L.	14905	8/7/59	3	4/2/58	Coffee Bay	Lafourche	20	6,558.8	20.50	22.55	24.5	26.55
Hunt, Lyda Bunker, Estate of Deceased	14904	8/7/59	10	4/2/58	Coffee Bay	Lafourche	20	j/	20.50	22.55	24.5	26.55
Secure Trusts	14903	8/7/59	6	4/2/58	Coffee Bay	Lafourche	20	j/	20.50	22.55	24.5	26.55
Hunt Oil Co.	15146	8/7/59	40	4/2/58	Triumph	Plaquemines	20	181.6	21.50	23.55	25.5	27.55
Texaco Inc.	15038	8/7/59	186	4/10/58	Felice Bayou	Plaquemines	20	309.1	19.00	20.50	23.0	24.50
Texas Gas Transmission Corporation												
Humble Oil & Refining Co.	14154	9/25/59	127	12/3/57	E. Lake Palourde	Assumption, St. Martin	20	2,426.3	20.00	21.75	23.3	25.05
United Gas Pipe Line Company												
Cities Service Petroleum Co.	14232	9/28/59	106	1/2/58	S. Lewisburg	Acadia	20	192.0	18.50	20.25	20.7	22.45
Sohio Petroleum Co.	14247	9/28/59	42	1/10/58	S. Lewisburg	Acadia	20	1,500.0	18.50	20.25	20.7	22.45

Purchaser Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume[a] (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement[b] (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement[b] (m)
									(Cents per Mcf at 15.025 psia)			
American Louisiana Pipe Line Company												
Humble Oil & Refining Co.	15365	10/5/59	140	6/2/58	Cheniere Perdue	Cameron	20	360.1	18.25	19.75	22.0	23.50
United Gas Pipe Line Company												
Hudson Gas & Oil Corp., et al.	15377	10/5/59	3	5/9/58	N. W. Branch	Acadia	20	262.5	18.50	20.25	20.7	22.45
Trunkline Gas Company												
Austral Oil Co., Inc.	15819	10/27/59	13	7/18/58	N. Freshwater Bayou	Vermilion	22	857.0	22.00	24.05[i]	26.3	28.35[i]
United Gas Pipe Line Company												
Trice Production Co.	18885	1/27/60	12	6/16/59	Sunrise	Terrebonne	20	192.0	20.00	22.05	21.5	23.55
United Fuel Gas Company												
MPS Production Co., Inc., et al.	15813	2/5/60	1	7/17/58	Erath	Vermilion	21	471.7	20.60	22.10	22.7	24.20
Pan American Petroleum Corp.	15047	2/5/60	219	1/9/58	Erath	Vermilion	21	1,295.1	20.60	22.10	22.6	24.10
American Louisiana Pipe Line Company												
Tidewater Oil Co.	15707	3/18/60	74	7/10/58	Second Bayou	Cameron	Life	90.0	18.00	19.50	22.1	23.60
Southern Natural Gas Company												
Callery, Francis A. (Op.), et al.	15404	3/18/60	15	2/1/58	Coquille Bay	Plaquemines	20	187.7	19.00	20.75	20.5	22.25
United Fuel Gas Company												
Midwest Oil Corp. (Op.), et al.	17887	3/18/60	15	12/29/58	Branch	Acadia	20	583.7	17.60	19.10	20.3	21.80
Southern Natural Gas Company												
Continental Oil Co.	17520	5/3/60	175	10/27/58	N. Bayou Long	Iberia	20	35.7	21.50	23.675	25.5	27.675
United Gas Pipe Line Company												
Conover, William V.	19195	5/31/60	1	7/13/59	Lapeyrouse	Terrebonne	18	18.0	18.50	20.25	20.9	22.65
Hudson Gas & Oil Corp.	15989	5/31/60	4	11/8/57	Theall	Vermilion	20	218.4	18.50	20.25	20.7	22.45
Trice Production Co.	16543	5/31/60	8	9/22/58	S. Martinville	St. Martin	20	302.2	18.50	20.00	20.8	22.30
American Louisiana Pipe Line Company												
Austral Oil Co., Inc. (Op.), et al.	10386	6/8/60	8	2/9/56	W. Little Cheniere	Cameron	20	740.7	18.25	19.75	22.0	23.50
Petroleum Leaseholds, Inc.	10386	6/8/60	4	1/23/56	Little Chenier	Cameron	20	750.9	18.25	19.75	22.0	23.50
Tidewater Oil Co.	17634	6/8/60	82	12/31/58	N. Holly Beach	Cameron	Life	100.4	18.00	19.50	22.3	23.80
Texas Gas Transmission Corporation												
Frankel, J. R.	18391	6/8/60	3	3/30/59	E. Lake Palourde	Assumption	20	193.5	20.00	21.75	23.7	25.45
Trahan, J. D., Drilling Contractor, Inc.	60-394	7/11/60	8	2/29/60	Bayou Chevreuil	Lafourche, St. James, St. John the Baptist	20	1,008.0	20.00	21.75	22.9	24.65

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement b/ (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement b/ (m)
									(Cents per Mcf at 15.025 psia)			
American Louisiana Pipe Line Company												
Humble Oil & Refining Co.	18605	7/14/60	156	4/24/59	E. Cheniere Perdue	Cameron	20	742.8	18.25	19.75	22.0	23.50
Texas Gas Transmission Corporation												
Argo Oil Corp.	16151	7/14/60	37	6/18/58	Jeanerette	St. Mary	20	k/	19.00	20.75	20.8	22.55
Southwest Gas Producing Co., Inc. (Op.), et al.	16150	7/14/60	12	6/18/58	Jeanerette	St. Mary	20	4,822.5	19.00	20.75	20.8	22.55
United Fuel Gas Company												
Midwest Oil Corp. (Op.), et al.	17471	7/14/60	14	12/29/58	Ellis	Acadia	20	937.9	17.60	19.10	20.3	21.80
American Louisiana Pipe Line Company												
Union Producing Co.	13684	8/10/60	217	9/18/56	Second Bayou	Cameron	Life	908.6	18.00	19.50	21.8	23.30
Southern Natural Gas Company												
Phillips Petroleum Co.	19976	8/10/60	354	9/14/59	Mystic Bayou	St. Martin	20	720.0	21.50	23.25	25.5	27.25
United Gas Pipe Line Company												
Texaco Inc.	18174	8/10/60	194	3/10/59	Welsh	Jefferson Davis	20	518.1	18.50	20.25	20.7	22.45
American Louisiana Pipe Line Company												
Fifteen Oil Co.	18820	9/20/60	2	1/1/59	E. Cheniere Perdue	Cameron	20	495.1	18.25	19.75	22.0	23.50
Southern Natural Gas Company												
Continental Oil Co.	19437	9/20/60	172	4/30/59	Bayou Long	Iberia, St. Martin	20	45.3	21.50	23.675	25.7	27.875
United Fuel Gas Company												
Owen, J. P.	19313	10/31/60	3	8/5/59	Duson	Lafayette	20	360.0	18.00	19.50	20.5	22.00
Texaco Inc.	19121	10/31/60	200	7/9/59	Midland	Acadia	20	540.0	17.60	19.10	20.5	22.00
Trunkline Gas Company												
California Co., The	60-215	11/29/60		1/27/60	S. Mermentau, Riceville	Acadia, Vermilion	20	1,302.0	21.50	23.25	25.9	27.65
Humble Oil & Refining Co., et al.	60-259	11/29/60		1/22/60	Bayou Sale, Bayou Carlin	St. Mary	20	21,600.0	21.50	23.25	25.9	27.65
Richardson & Bass (Op.), et al.	60-209	11/29/60		12/24/59	S. Mermentau, Riceville	Acadia, Vermilion	20	NR	21.50	23.25	25.9	27.65
United Fuel Gas Company												
Humble Oil & Refining Co.	19416	12/21/60	166	7/20/59	Calcasieu Pass	Cameron	20	558.0	18.00	19.50	20.4	21.90
Southern Natural Gas Company												
Atlantic Refining Co., The	60-264	3/10/61	211	11/30/59	Saturday Island	Plaquemines, Jefferson	20	597.6	17.00	19.175	21.0	23.175

Purchaser / Filing Company (a)	Docket Number (G- or CI-) (b)	Date of FPC Order (c)	Rate Sch. No. (d)	Date of Contract (e)	Field (f)	Parish (g)	Term (Yrs) (h)	Annual Volume a/ (MMcf at 15.025) (i)	Initial Base Price (j)	Initial Base Price Plus Tax Reimbursement (k)	Average Base Price (l)	Average Base Price Plus Tax Reimbursement (m)
									(Cents per Mcf at 15.025 psia)			
United Fuel Gas Company												
Pan American Petroleum Corp.	16758	3/10/61	240	10/2/58	Florence	Vermilion	20	784.4	17.60	19.10	20.2	21.70
United Gas Pipe Line Company												
Bel Oil Corp. (Op.), et al.	60-280	3/10/61	10	1/20/60	N. W. Oberlin Area	Allen	20	135.6	18.50	20.375	20.9	22.575
Hunt, Haroldson L., Jr., Trust Estate	60-151	3/10/61	4	1/26/60	W. Pilgrim Church	Allen	20	1/	18.50	20.375	20.7	22.575
Hunt, H. L	60-152	3/10/61	32	1/26/60	W. Pilgrim Church	Allen	20	1/	18.50	20.375	20.7	22.575
Hunt, Lamar	60-150	3/10/61	8	1/26/60	W. Pilgrim Church	Allen	20	2,430.0	18.50	20.375	20.7	22.575

FA-4633

SOURCE

All contracts in South Louisiana filed with the Federal Power Commission for the sale of gas to interstate pipelines, which have a term of 15 years or longer (or life of reserves), have an average base price of 20 cents per Mcf or more, and which have been granted permanent certification by the FPC. All cases in which the Commission's order issuing the permanent certificate is under court or Commission review have been omitted from this listing.

FOOTNOTES

a/1960 volumes obtained from Form 2 reports of pipelines filed with the Federal Power Commission. For contracts where no 1960 deliveries were made, volume is based on estimated first-month deliveries as reported by producers at the time the contract was filed.

b/Tax reimbursement payable based on the severance tax charged by the State of Louisiana. The tax reimbursement shown is that to which the seller has been entitled since December 1, 1958 under the terms of his contract as filed with the Federal Power Commission. Cases in which a question has been raised by the FPC concerning interpretation of the tax reimbursement provisions of the contract as they relate to the severance tax have been footnoted.

c/The tax reimbursement filed for by the seller was suspended until 1/30/59 by the FPC order issued 1/28/59 in Docket No. G-17705 because of a question concerning interpretation of the tax reimbursement provisions of the contract as they relate to the severance tax.

d/Volume is included with the volume shown for Phillips Petroleum Co. Rate Schedule No. 301.

e/Volume is included with the volume shown for Lyons and Logan (Op.), et al. Rate Schedule No. 8.

f/Volume is included with the volume shown for Texaco Seaboard, Inc. Rate Schedule No. 23.

g/Buyer and seller are associated companies.

h/Volume is included with the volume shown for The British-American Oil Producing Co. Rate Schedule No. 31.

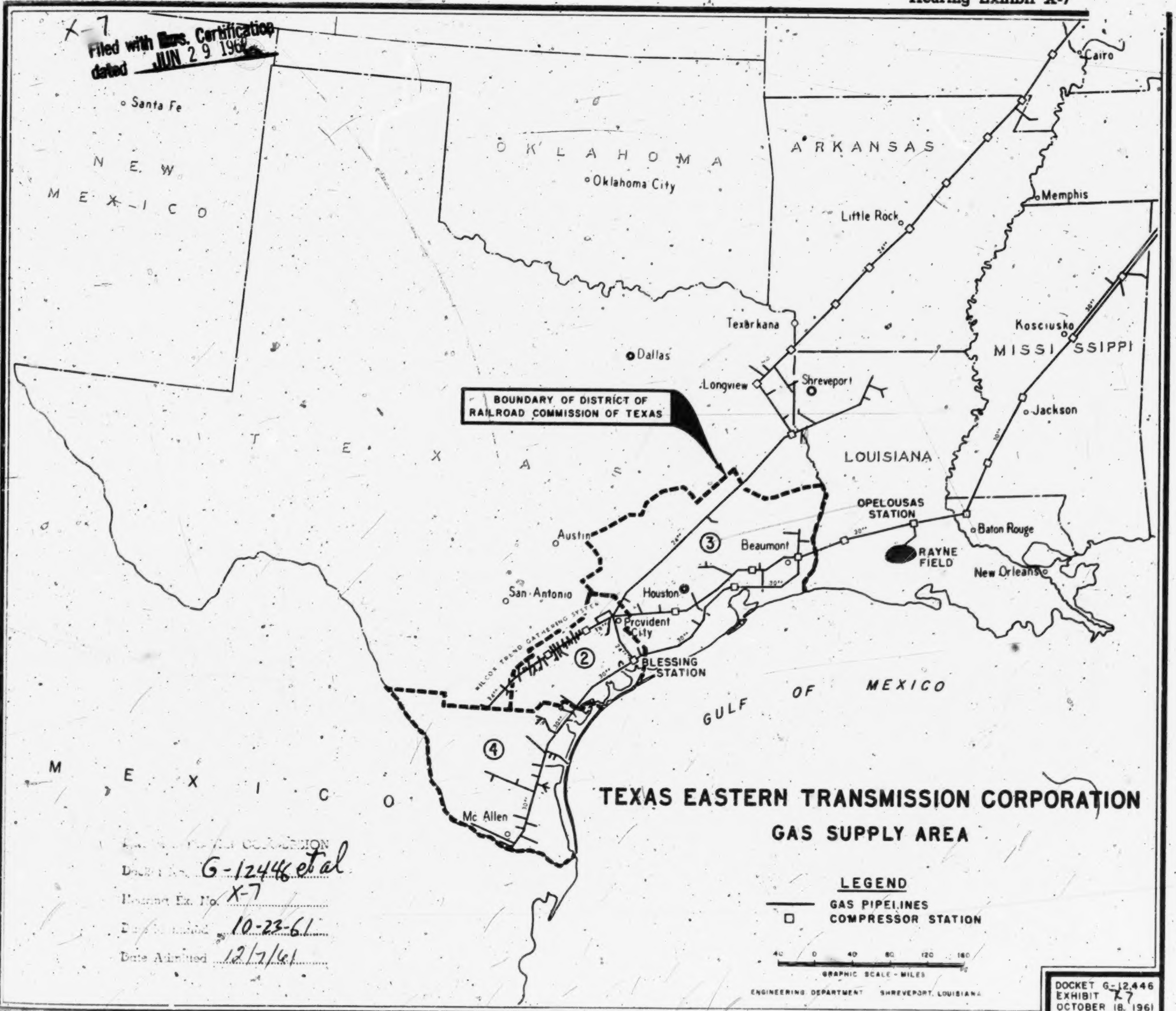
i/By order dated 12/23/59, the FPC conditionally accepted these rate schedules for filing because of a question concerning interpretation of the tax reimbursement provisions of the contracts as they relate to the severance tax.

j/Volume is included with the volume shown for H. L. Hunt Rate Schedule No. 30.

k/Volume is included with the volume shown for Southwest Gas Producing Co., Inc. (Op.), et al. Rate Schedule No. 12.

l/Volume is included with the volume shown for Lamar Hunt Rate Schedule No. 8.

m/The tax reimbursement filed for by the seller was suspended until 2/1/59 by FPC order issued 1/28/59 in Docket No. 17707 because of a question concerning interpretation of the tax reimbursement provisions of the contract as they relate to the severance tax.


X-7
Filed with Exs. Certification
dated JUN 29 1962
Santa Fe
NEW MEXICO
OKLAHOMA
Oklahoma City
ARKANSAS
Little Rock
Memphis
Cairo
Texarkana
Dallas
Longview
Shreveport
MISSISSIPPI
Kosciusko
Jackson
BOUNDARY OF DISTRICT OF RAILROAD COMMISSION OF TEXAS
TEXAS
LOUISIANA
OPELOUSAS STATION
Baton Rouge
RAYNE FIELD
New Orleans
Austin
Beaumont
San Antonio
Houston
Provident City
WILCOX TREND GATHERING SYSTEM
BLESSING STATION
GULF OF MEXICO
MEXICO
Mc Allen
Docket No. G-12446 et al
Hearing Ex. No. X-7
Date Submitted 10-23-61
Date Admitted 12/7/61
TEXAS EASTERN TRANSMISSION CORPORATION
GAS SUPPLY AREA
LEGEND
GAS PIPELINES
COMPRESSOR STATION
GRAPHIC SCALE - MILES
ENGINEERING DEPARTMENT SHREVEPORT, LOUISIANA
DOCKET G-12,446
EXHIBIT X-7
OCTOBER 18, 1961

815

Hearing Exhibit X-8 **(3812)**

Docket No. G-12446 et al.
Exhibit No. X-8

Filed with Exrs. Certification
dated JUN 29 1962

TEXAS EASTERN TRANSMISSION CORPORATION

Rayne Field
Schedule of Activity in the Other Deferred Debits Account
Years 1961 Through 1989

Line No.	(A) Year	(B) Balance at Jan. 1	(C) Add Note Payments*	(D) Deduct Depletion of Gas Reserve*
1	1961	$ 470,000	$ 8,259,400	$ 6,492,600
2	1962	2,236,800	8,258,000	6,492,600
3	1963	4,002,200	8,254,500	6,492,600
4	1964	5,764,100	8,252,300	6,492,600
5	1965	7,523,800	8,251,000	6,492,600
6	1966	9,282,200	8,258,100	6,492,600
7	1967	11,047,700	8,254,500	6,492,600
8	1968	12,809,600	8,252,300	6,492,600
9	1969	14,569,300	8,251,000	6,492,600
10	1970	16,327,700	8,256,700	6,492,600
11	1971	18,091,800	8,252,000	6,492,600
12	1972	19,851,200	8,158,400	6,492,600
13	1973	21,517,000	8,052,100	6,492,600
14	1974	23,076,500	8,005,500	5,736,400
15	1975	25,345,600	2,001,200	4,772,100
16	1976	22,574,700	-	4,136,700
17	1977	18,438,000	-	3,582,300
18	1978	14,855,700	-	2,954,500
19	1979	11,901,200	-	2,580,600
20	1980	9,320,600	-	2,097,100
21	1981	7,223,500	-	1,772,400
22	1982	5,451,100	-	1,471,300
23	1983	3,979,800	-	901,800
24	1984	3,078,000	-	755,900
25	1985	2,322,100	-	626,200
26	1986	1,695,900	-	570,400
27	1987	1,125,500	-	511,700
28	1988	613,800	-	324,700
29	1989	289,100	-	289,100
	Totals		$117,017,000	$117,487,000

*Based on Production Estimated on Exhibit X-2, Page 2, Docket No. G-12446.

G-12446 Cal.

Hearing Exhibit X-9 (3813)

Filed with Exrs. Certification dated JUN 29 1962

Docket No. G-12446 et al.
Exhibit No. X-9

TEXAS EASTERN TRANSMISSION CORPORATION

Statement of Rayne Field Properties included in Gas Plant in Service and the related Reserves for Depreciation, Depletion and Amortization
December 31, 1960

Rayne Field properties and the related reserves for depreciation, depletion and amortization which were on the Company's books as of December 31, 1960 are as follows:

	Plant	Reserves
Producing Leaseholds	$ 8,471,200	$ 514,900
Producing Gas Wells - Well Constr.	481,300	10,500
Structures, Equip. & Rights-of-Way	5,243,000	568,400
Totals	$ 14,195,500	$ 1,093,800

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Exhibit X-9
Date 11-29-61
Rep 12/7/61

Hearing Exhibit X-10 (3814)

Docket No. G-12446 et al.
Exhibit No. X-10

Filed with Exrs. Certification dated JUN 29 1962

TEXAS EASTERN TRANSMISSION CORPORATION
Rayne Field
Balances of Tangible Plant, Natural Gas
Producing Leaseholds and Intangible Drilling Costs
Less Applicable Reserves at January 1 Each Year
For The Years 1961 Through 1989

Line No.	(A) Year	(B) Balance of Tangible Plant	(C) Balance of Nat'l Gas Prod. Leaseholds	(D) Balance of Intangible Drilling Costs	(E) Total
1	1961	$ 4,674,600	$ 7,956,300	$ 470,800	$13,101,700
2	1962	4,477,000	7,516,600	444,800	12,438,400
3	1963	4,715,100	7,076,900	918,800	12,710,800
4	1964	4,422,100	6,637,200	861,700	11,921,000
5	1965	4,129,100	6,197,500	804,600	11,131,200
6	1966	3,836,100	5,757,800	747,500	10,341,400
7	1967	3,543,100	5,318,100	690,400	9,551,600
8	1968	3,250,100	4,878,400	633,300	8,761,800
9	1969	2,957,100	4,438,700	576,200	7,972,000
10	1970	2,664,100	3,999,000	519,600	7,182,700
11	1971	2,371,100	3,559,300	462,100	6,392,500
12	1972	2,328,200	3,119,600	655,100	6,102,900
13	1973	2,284,300	2,679,900	813,600	5,777,800
14	1974	1,925,600	2,240,200	680,100	4,845,900
15	1975	1,591,700	1,851,800	562,200	4,005,700
16	1976	1,314,000	1,528,600	464,100	3,306,700
17	1977	1,140,700	1,248,500	536,500	2,925,700
18	1978	986,600	1,005,900	589,800	2,582,300
19	1979	790,400	805,900	472,500	2,068,800
20	1980	664,000	631,200	475,000	1,770,200
21	1981	627,100	489,200	630,600	1,746,900
22	1982	540,700	369,200	633,400	1,543,300
23	1983	439,800	269,600	568,300	1,277,700
24	1984	340,100	208,500	439,500	988,100
25	1985	256,600	157,300	331,500	745,400
26	1986	187,400	114,900	242,100	544,400
27	1987	124,400	76,300	160,600	361,300
28	1988	67,800	41,600	87,500	196,900
29	1989	31,900	19,600	41,100	92,600

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Hearing X-10
11-29-61
12/7/61

Hearing Exhibit X-11 (3815)

Filed with Exrs. Certification dated JUN 29 1962

Docket No. G-12446 et al.
Exhibit No. X-11

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Exhibit No. X-11
Date 11-29-61
Date Admitted 12/7/61

TEXAS EASTERN TRANSMISSION CORPORATION

Rayne Field
Net Liquids Revenues
Years 1961 Through 1989

	(A)	(B)	(C)	(D)	(E)
		Non-Recoverable	Liquids Revenue - Credit		Net
Line No.	Year	Oper. & Maint. Expense (1)	Separator (2)	Natural Gas (3)	Liquids Revenues
1	1961	$ -	$ -	$ -	$ -
2	1962	-	-	-	-
3	1963	-	-	-	-
4	1964	-	-	-	-
5	1965	-	-	-	-
6	1966	-	-	-	-
7	1967	-	-	-	-
8	1968	-	-	-	-
9	1969	-	-	-	-
10	1970	100	800	200	(900)
11	1971	200	900	300	(1,000)
12	1972	13,100	48,500	13,900	(49,300)
13	1973	25,300	81,500	24,600	(80,800)
14	1974	27,500	79,400	24,400	(76,300)
15	1975	693,000	1,802,500	564,700	(1,674,200)
16	1976	796,900	1,847,400	588,000	(1,638,500)
17	1977	766,900	1,592,000	511,900	(1,337,000)
18	1978	707,200	1,308,200	420,500	(1,021,500)
19	1979	659,200	1,170,800	376,200	(887,800)
20	1980	629,400	975,100	313,700	(659,400)
21	1981	545,500	842,300	271,400	(568,200)
22	1982	497,500	695,500	223,100	(421,100)
23	1983	467,700	447,100	136,900	(116,300)
24	1984	305,700	373,900	113,700	(181,900)
25	1985	275,800	310,500	94,500	(129,200)
26	1986	275,800	281,400	85,500	(91,100)
27	1987	275,800	251,100	76,300	(51,600)
28	1988	210,000	187,000	59,000	(36,000)
29	1989	209,800	166,400	52,500	(9,100)
	Totals	$ 7,382,400	$12,462,300	$ 3,951,300	$(9,031,200)

(1) Sum of non-recoverable amounts (after production payments) shown on pages 8, 9 and 14 of Exhibit X-5.
(2) From Exhibit X-5, page 10 (after production payments).
(3) From Exhibit X-5, page 11, 60% of net interest in production (after production payments).

TEXAS EASTERN TRANSMISSION CORPORATION

Filed with E
dated ___

Schedule of Rayne Field Note Payments
Based on Production Estimated on Exhibit X-2, Page 2, Docket No. G-12446

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Conoco, et al		Dishman, et al		Kirby		Muller	
Line No.	Calendar Year	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount
1	1959 - Regular Installments	3	$ 1,570,899.00	3	$ 13,574.19	3	$ 8,613.66	3	$ 16,979.82
2	1960 - Regular Installments	12	6,283,596.00	12	54,296.76	12	34,454.64	12	67,919.28
3	1960 - Accelerated Installments	-	-	-	-	2	7,391.32	-	-
4	1961 - Regular Installments	12	6,714,063.00	12	58,215.87	12	36,941.55	12	72,821.67
5	1961 - Accelerated Installments	2	1,334,244.00	2	11,647.94	5	18,478.30	1	7,285.15
6	1962 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
7	1962 - Accelerated Installments	-	-	2	11,647.94	2	7,395.85	4	29,140.60
8	1963 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
9	1963 - Accelerated Installments	-	-	2	11,647.94	3	11,100.57	3	21,855.45
10	1964 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
11	1964 - Accelerated Installments	-	-	1	5,823.97	2	7,400.38	4	29,176.28
12	1965 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
13	1965 - Accelerated Installments	-	-	2	11,655.07	2	7,400.38	3	21,882.21
14	1966 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
15	1966 - Accelerated Installments	-	-	2	11,662.20	2	7,400.38	4	29,176.28
16	1967 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
17	1967 - Accelerated Installments	-	-	2	11,662.20	3	11,100.57	3	21,882.21
18	1968 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
19	1968 - Accelerated Installments	-	-	1	5,831.10	2	7,400.38	4	29,176.28
20	1969 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
21	1969 - Accelerated Installments	-	-	2	11,662.20	2	7,400.38	3	21,882.21
22	1970 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
23	1970 - Accelerated Installments	-	-	2	11,662.20	2	7,400.38	4	29,176.28
24	1971 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84
25	1971 - Accelerated Installments	-	-	2	11,662.20	3	11,100.57	3	21,882.21
26	1972 - Regular Installments	12	8,005,464.00	12	69,973.20	9	33,301.71	5	36,470.35
27	1972 - Accelerated Installments	-	-	1	5,831.10	2	7,400.38	-	-
28	1973 - Regular Installments	12	8,005,464.00	7	40,817.70	-	-	-	-
29	1973 - Accelerated Installments	-	-	1	5,831.10	-	-	-	-
30	1974 - Regular Installments	12	8,005,464.00	-	-	-	-	-	-
31	1974 - Accelerated Installments	-	-	-	-	-	-	-	-
32	1975 - Regular Installments	3	2,001,366.00	-	-	-	-	-	-
33	1975 - Accelerated Installments	-	-	-	-	-	-	-	-
	Total	188	$121,975,200.00	188	$1,064,836.88	188	$675,704.20	188	$1,331,994.68

Hearing Exhibit X-12 (3816)

Docket No. G-12446 et al.
Exhibit No. X-12

Filed with Exrs. Certification dated JUN 29 196

TEXAS EASTERN TRANSMISSION CORPORATION

Schedule of Rayne Field Note Payments
Based on Production Estimated on Exhibit X-2, Page 2, Docket No. G-12446

(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Conoco, et al		Dishman, et al		Kirby		Muller		Texas Gas		
No. of tallments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	Total Amount
3	$ 1,570,899.00	3	$ 13,574.19	3	$ 8,613.66	3	$ 16,979.82	3	$ 414.42	$ 1,610,481.09
12	6,283,596.00	12	54,296.76	12	34,454.64	12	67,919.28	12	1,657.68	6,441,924.36
-	-	-	-	2	7,391.32	-	-	19	3,380.81	10,772.13
12	6,714,063.00	12	58,215.87	12	36,941.55	12	72,821.67	12	1,777.35	6,883,819.44
2	1,334,244.00	2	11,647.94	5	18,478.30	1	7,285.15	22	3,916.66	1,375,572.05
12	8,005,[illegible].00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,647.94	2	7,395.85	4	29,140.60	2	356.06	48,540.45
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,647.94	3	11,100.57	3	21,855.45	2	356.06	44,960.02
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	1	5,823.97	2	7,400.38	4	29,176.28	2	356.06	42,756.69
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,655.07	2	7,400.38	3	21,882.21	3	534.09	41,471.75
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,662.20	2	7,400.38	4	29,176.28	2	356.06	48,594.92
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,662.20	3	11,100.57	3	21,882.[illegible]	2	356.06	45,001.04
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.[illegible]	12	2,136.36	8,209,504.68
-	-	1	5,831.10	2	7,400.38	4	29,176.28	2	356.06	42,763.82
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
-	-	2	11,662.20	2	7,400.38	3	21,882.21	3	534.09	41,478.88
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	6	1,068.18	8,208,436.50
-	-	2	11,662.20	2	7,400.38	4	29,176.28	-	-	48,238.86
12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	-	-	8,207,368.32
-	-	2	11,662.20	3	11,100.57	3	21,882.21	-	-	44,644.98
12	8,005,464.00	12	69,973.20	9	33,301.71	5	36,470.35	-	-	8,145,209.26
-	-	1	5,831.10	2	7,400.38	-	-	-	-	13,231.48
12	8,005,464.00	7	40,817.70	-	-	-	-	-	-	8,046,281.70
-	-	1	5,831.10	-	-	-	-	-	-	5,831.10
12	8,005,464.00	-	-	-	-	-	-	-	-	8,005,464.00
-	-	-	-	-	-	-	-	-	-	-
3	2,001,366.00	-	-	-	-	-	-	-	-	2,001,366.00
-	-	-	-	-	-	-	-	-	-	-
188	$121,975,200.00	188	$1,064,836.88	188	$675,704.20	188	$1,331,994.68	188	$32,510.52	$125,080,246.28

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Hearing Ex. No. X-12
Date Identified 11-29-61
Date Admitted 12/7/61

Hearir

Filed with Exrs. Certifie
dated JUN 2 9 195

TEXAS EASTERN TRANSMISSION CORPORATION

Schedule of Rayne Field Note Payments
Assuming No Accelerated Installments

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		Conoco, et al		Dishman, et al		Kirby		Muller		T
Line No.	Calendar Year	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installm
1	1959 - Regular Installments	3	$ 1,570,899.00	3	$ 13,574.19	3	$ 8,613.66	3	$ 16,979.82	3
2	1960 - Regular Installments	12	6,283,596.00	12	54,296.76	12	34,454.64	12	67,919.28	12
3	1960 - Accelerated Installments	-	-	-	-	-	-	-	-	-
4	1961 - Regular Installments	12	6,714,063.00	12	58,215.87	12	36,941.55	12	72,821.67	12
5	1961 - Accelerated Installments	-	-	-	-	-	-	-	-	-
6	1962 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
7	1962 - Accelerated Installments	-	-	-	-	-	-	-	-	-
8	1963 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
9	1963 - Accelerated Installments	-	-	-	-	-	-	-	-	-
10	1964 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
11	1964 - Accelerated Installments	-	-	-	-	-	-	-	-	-
12	1965 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
13	1965 - Accelerated Installments	-	-	-	-	-	-	-	-	-
14	1966 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
15	1966 - Accelerated Installments	-	-	-	-	-	-	-	-	-
16	1967 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
17	1967 - Accelerated Installments	-	-	-	-	-	-	-	-	-
18	1968 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
19	1968 - Accelerated Installments	-	-	-	-	-	-	-	-	-
20	1969 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
21	1969 - Accelerated Installments	-	-	-	-	-	-	-	-	-
22	1970 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
23	1970 - Accelerated Installments	-	-	-	-	-	-	-	-	-
24	1971 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
25	1971 - Accelerated Installments	-	-	-	-	-	-	-	-	-
26	1972 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
27	1972 - Accelerated Installments	-	-	-	-	-	-	-	-	-
28	1973 - Regular Installments	12	8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12
29	1973 - Accelerated Installments	-	-	-	-	-	-	-	-	-
30	1974 - Regular Installments	12	8,005,464.00	12	69,951.81	12	44,388.69	12	87,502.08	12
31	1974 - Accelerated Installments	-	-	-	-	-	-	-	-	-
32	1975 - Regular Installments	5	3,335,660.00	5	29,119.85	5	18,478.30	5	36,425.75	5
33	1975 - Accelerated Installments	-	-	-	-	-	-	-	-	-
	Total	188	$121,975,200.00	188	$1,054,836.88	188	$675,704.20	188	$1,331,994.68	188

Hearing Exhibit X-13 (3817)

Docket No. G-12446 et al.
Exhibit No. X-13

Filed with Exrs. Certification dated JUN 29 1964

TEXAS EASTERN TRANSMISSION CORPORATION

Schedule of Rayne Field Note Payments
Assuming No Accelerated Installments

(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
oco, al	Dishman, et al		Kirby		Muller		Texas Gas		
Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	No. of Installments	Amount	Total Amount
$ 1,570,899.00	3	$ 13,574.19	3	$ 8,613.66	3	$ 16,979.82	3	$ 414.42	$ 1,610,481.09
6,283,596.00	12	54,296.76	12	34,454.64	12	67,919.28	12	1,657.68	6,441,924.36
6,714,063.00	12	58,215.87	12	36,941.55	12	72,821.67	12	1,777.35	6,883,819.44
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,973.20	12	44,402.28	12	87,528.84	12	2,136.36	8,209,504.68
8,005,464.00	12	69,951.31	12	44,388.69	12	87,502.08	12	2,135.70	8,209,442.28
3,335,660.00	5	29,119.85	5	18,478.30	5	36,425.75	5	889.05	3,420,522.95
$121,975,200.00	188	$1,064,836.88	188	$675,704.20	188	$1,331,994.68	188	$32,510.52	$125,080,246.28

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Hearing Ex. No. X-13
Date Identified 11-29-61
Date Admitted 12/7/61

Filed with Exrs. Certification
dated JUN 29 196

TEXAS EASTERN TRANSMISSION CORPORATION
Rayne Field
Cost of Gas Per Exhibit X-4 Adjusted to Include
Outside Interests Gas as well as Louisiana Severance Tax
Years 1961 Through 1989

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Production (MMCF)				Include Outside Interest Gas		
Line No.	Year	Working Interest (1)	Other Interest (1)	Total	Total Cost of Gas (Exh. X-4)	Outside Int. @22.1563¢/MCF	Adjusted Total (E) + (F)	Cost Per MCF (2)
1	1961	41,691	9,409	51,100	$ 7,216,600	$ 2,084,700	$ 9,301,300	18.20¢
2	1962	41,691	9,409	51,100	7,220,200	2,084,700	9,304,900	18.21¢
3	1963	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
4	1964	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
5	1965	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
6	1966	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
7	1967	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
8	1968	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
9	1969	41,691	9,409	51,100	7,282,400	2,084,700	9,367,100	18.33¢
10	1970	41,691	9,409	51,100	7,281,500	2,084,700	9,366,200	18.33¢
11	1971	41,691	9,409	51,100	7,281,400	2,084,700	9,366,100	18.33¢
12	1972	41,691	9,409	51,100	7,303,400	2,084,700	9,388,100	18.37¢
13	1973	41,691	9,409	51,100	7,359,800	2,084,700	9,444,500	18.48¢
14	1974	36,835	8,313	45,148	6,500,300	1,841,900	8,342,200	18.48¢
15	1975	30,643	6,915	37,558	3,796,900	1,532,100	5,329,000	14.19¢
16	1976	26,563	5,994	32,557	3,104,200	1,328,000	4,432,200	13.61¢
17	1977	23,003	5,191	28,194	2,813,700	1,150,100	3,963,800	14.06¢
18	1978	18,972	4,282	23,254	2,446,500	948,700	3,395,200	14.60¢
19	1979	16,571	3,740	20,311	2,141,400	828,600	2,970,000	14.62¢
20	1980	13,466	3,039	16,505	1,836,000	673,300	2,509,300	15.20¢
21	1981	11,381	2,568	13,949	1,632,800	569,000	2,201,800	15.78¢
22	1982	9,448	2,132	11,580	1,465,800	472,400	1,938,200	16.74¢
23	1983	5,791	1,307	7,098	1,075,100	289,600	1,364,700	19.23¢
24	1984	4,854	1,096	5,950	816,700	242,800	1,059,500	17.81¢
25	1985	4,021	907	4,928	698,000	201,000	899,000	18.24¢
26	1986	3,663	827	4,490	662,400	183,200	845,600	18.83¢
27	1987	3,286	742	4,028	624,500	164,400	788,900	19.59¢
28	1988	2,085	470	2,555	393,000	104,100	497,100	19.46¢
29	1989	1,855	418	2,273	372,600	92,600	465,200	20.47¢
	Totals	754,420	170,258	924,678	$125,019,600	$37,722,900	$162,742,500	17.60¢

(1) Working Interest = 81.58729%; Outside Interests = 18.41271% per Exhibit X-5, Page 13.
(2) Based on total production in Column D.

Hearing Exhibit X-14 **(3818)**

Docket No. G-12446 et al.
Exhibit No. X-14

FEDERAL POWER COMMISSION
Docket No. G-12446 et al
Hearing Exh. No. X-14
Date ... 11-29-61
... 12/7/61

TEXAS EASTERN TRANSMISSION CORPORATION
Rayne Field
Cost of Gas Per Exhibit X-4 Adjusted to Include
Outside Interests Gas as well as Louisiana Severance Tax
Years 1961 Through 1989

(MMCF) (1)	(D)	(E)	(F) Include Outside Interest Gas	(G)	(H)	(I) Include La. Severance Tax	(J)	(K)
t	Total	Total Cost of Gas (Exh. X-4)	Outside Int. @22.1563¢/MCF	Adjusted Total (E) + (F)	Cost Per MCF (2)	Tax @2.2548¢ Per W.I. MCF	Adjusted Total (G) + (I)	Cost Per MCF (2)
09	51,100	$ 7,216,600	$ 2,084,700	$ 9,301,300	18.20¢	$ 940,100	$ 10,241,400	20.04¢
09	51,100	7,220,200	2,084,700	9,304,900	18.21¢	940,100	10,245,000	20.05¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,100	10,307,200	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,282,400	2,084,700	9,367,100	18.33¢	940,000	10,307,100	20.17¢
09	51,100	7,281,500	2,084,700	9,366,200	18.33¢	940,000	10,306,200	20.17¢
09	51,100	7,281,400	2,084,700	9,366,100	18.33¢	940,000	10,306,100	20.17¢
09	51,100	7,303,400	2,084,700	9,388,100	18.37¢	940,000	10,328,100	20.21¢
09	51,100	7,359,800	2,084,700	9,444,500	18.48¢	940,000	10,384,500	20.32¢
13	45,148	6,500,300	1,841,900	8,342,200	18.48¢	830,600	9,172,800	20.32¢
15	37,558	3,796,900	1,532,100	5,329,000	14.19¢	691,000	6,020,000	16.03¢
94	32,557	3,104,200	1,328,000	4,432,200	13.61¢	599,000	5,031,200	15.45¢
91	28,194	2,813,700	1,150,100	3,963,800	14.06¢	518,700	4,482,500	15.90¢
32	23,254	2,446,500	948,700	3,395,200	14.60¢	427,800	3,823,000	16.44¢
40	20,311	2,141,400	828,600	2,970,000	14.62¢	373,700	3,343,700	16.46¢
39	16,505	1,836,000	673,300	2,509,300	15.20¢	303,700	2,813,000	17.04¢
58	13,949	1,632,800	569,000	2,201,800	15.78¢	256,600	2,458,400	17.62¢
32	11,580	1,465,800	472,400	1,938,200	16.74¢	213,000	2,151,200	18.58¢
07	7,098	1,075,100	289,600	1,364,700	19.23¢	130,600	1,495,300	21.07¢
96	5,950	816,700	242,800	1,059,500	17.81¢	109,500	1,169,000	19.65¢
07	4,928	698,000	201,000	899,000	18.24¢	90,700	989,700	20.08¢
27	4,490	662,400	183,200	845,600	18.83¢	82,600	928,200	20.67¢
2	4,028	624,500	164,400	788,900	19.59¢	74,100	863,000	21.43¢
70	2,555	393,000	104,100	497,100	19.46¢	47,000	544,100	21.30¢
8	2,273	372,600	92,600	465,200	20.47¢	41,800	507,000	22.31¢
8	924,678	$125,019,600	$37,722,900	$162,742,500	17.60¢	$17,010,700	$179,753,200	19.44¢

tside Interests = 18.41271% per Exhibit X-5, Page 13.

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 1

(A) YEAR	(B) TOTAL COST OF GAS PER EXHIBIT X-4	ADD: (C) RETURN @ 6%	ADD: (D) FED. INCOME TAX RE. TO RETURN	(E) TOTAL COST OF SERVICE	COST OF SERVICE PER MCF: (F) @ 14.73#	COST OF SERVICE PER MCF: (G) @ 15.025#
1961	$ 7 216 600	$ 786 100	$ 411 600	$ 8 414 300	20.18¢	20.58¢
1962	7 220 200	746 300	390 800	8 357 300	20.05¢	20.45¢
1963	7 282 400	762 700	399 300	8 444 400	20.25¢	20.66¢
1964	7 282 400	715 300	374 500	8 372 200	20.08¢	20.48¢
1965	7 282 400	667 900	349 700	8 300 000	19.91¢	20.31¢
1966	7 282 400	620 500	324 900	8 227 800	19.74¢	20.14¢
1967	7 282 400	573 100	300 100	8 155 600	19.56¢	19.95¢
1968	7 282 400	525 700	275 300	8 083 400	19.39¢	19.78¢
1969	7 282 400	478 300	250 500	8 011 200	19.22¢	19.60¢
1970	7 281 500	430 900	225 700	7 938 100	19.04¢	19.42¢
1971	7 281 400	383 500	200 800	7 865 700	18.87¢	19.25¢
1972	7 303 400	366 200	191 700	7 861 300	18.86¢	19.24¢
1973	7 359 800	346 600	181 500	7 887 900	18.92¢	19.30¢
1974	6 500 300	290 700	152 200	6 943 200	18.85¢	19.23¢
1975	3 796 900	240 300	125 800	4 163 000	13.59¢	13.86¢
1976	3 104 200	198 400	103 900	3 406 500	12.82¢	13.08¢
1977	2 813 700	175 600	91 900	3 081 200	13.39¢	13.66¢
1978	2 446 500	154 900	81 100	2 682 500	14.14¢	14.42¢
1979	2 141 400	124 100	65 000	2 330 500	14.06¢	14.34¢
1980	1 836 000	106 200	55 600	1 997 800	14.84¢	15.14¢
1981	1 632 800	104 800	54 900	1 792 500	15.75¢	16.07¢
1982	1 465 800	92 600	48 500	1 606 900	17.01¢	17.35¢
1983	1 075 100	76 700	40 100	1 191 900	20.58¢	20.99¢
1984	816 700	59 300	31 000	907 000	18.69¢	19.06¢
1985	698 000	44 700	23 400	766 100	19.05¢	19.43¢
1986	662 400	32 700	17 100	712 200	19.44¢	19.83¢
1987	624 500	21 700	11 400	657 600	20.01¢	20.41¢
1988	393 000	11 800	6 200	411 000	19.71¢	20.10¢
1989	372 600	5 600	2 900	381 100	20.54¢	20.95¢
TOTALS	$125 019 600	$ 9 143 200	$ 4 787 400	$138 950 200	18.42¢	18.79¢

Hearing Exhibit X-15. (3819)
DOCKET NOS. G-12446 ET AL
EXHIBIT NO. X-15

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 1

Filed with Exrs. Certification dated JUN 2 9 196[illegible]

(B) Total Cost of Gas per Exhibit X-4	(C) Add: Return @ 6%	(D) Add: Fed. Income Tax Rel. to Return	(E) Total Cost of Service	(F) Cost of Service per MCF @ 14.73#	(G) Cost of Service per MCF @ 15.025#
$ 7 216 600	$ 786 100	$ 411 600	$ 8 414 300	20.18¢	20.58¢
7 220 200	746 300	390 800	8 357 300	20.05¢	20.45¢
7 282 400	762 700	399 300	8 444 400	20.25¢	20.66¢
7 282 400	715 300	374 500	8 372 200	20.08¢	20.48¢
7 282 400	667 900	349 700	8 300 000	19.91¢	20.31¢
7 282 400	620 500	324 900	8 227 800	19.74¢	20.14¢
7 282 400	573 100	300 100	8 155 600	19.56¢	19.95¢
7 282 400	525 700	275 300	8 083 400	19.39¢	19.78¢
7 282 400	478 300	250 500	8 011 200	19.22¢	19.60¢
7 28[illegible] 500	430 900	225 700	7 938 100	19.04¢	19.42¢
7 281 400	383 500	200 800	7 865 700	18.87¢	19.25¢
7 303 400	366 200	191 700	7 861 300	18.86¢	19.24¢
7 359 800	346 600	181 500	7 887 900	18.92¢	19.30¢
6 500 300	290 700	152 200	6 943 200	18.85¢	19.23¢
3 796 900	240 300	125 800	4 163 000	13.59¢	13.86¢
3 104 200	198 400	103 900	3 406 500	12.82¢	13.08¢
2 813 700	175 600	91 900	3 081 200	13.39¢	13.66¢
2 446 500	154 900	81 100	2 682 500	14.14¢	14.42¢
2 141 400	124 100	65 000	2 330 500	14.06¢	14.34¢
1 836 000	106 200	55 600	1 997 800	14.84¢	15.14¢
1 632 800	104 800	54 900	1 792 500	15.75¢	16.07¢
1 465 800	92 600	48 500	1 606 900	17.01¢	17.35¢
1 075 100	76 700	40 100	1 191 900	20.58¢	20.99¢
816 700	59 300	31 000	907 000	18.69¢	19.06¢
698 000	44 700	23 400	766 100	19.05¢	19.43¢
662 400	32 700	17 100	712 200	19.44¢	19.83¢
624 500	21 700	11 400	657 600	20.01¢	20.41¢
393 000	11 800	6 200	411 000	19.71¢	20.10¢
372 600	5 600	2 900	381 100	20.54¢	20.95¢
$125 019 600	$ 9 143 200	$ 4 787 400	$138 950 200	18.42¢	18.79¢

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 2

Filed with
dated

(A) Year	(B) Total Cost of Gas per Exhibit X-4	(C) Add La. Severance Tax on W.I. Gas (1)	(D) Total Cost of Gas Before Return & F.I.T.	(E) Add Return at 6%	(F) Add Fed. Income Tax re. Return	(G) Total Cost of Service
1961	$ 7 216 600	$ 940 100	$ 8 156 700	$ 786 100	$ 411 600	$ 9 354 400
1962	7 220 200	940 100	8 160 300	746 300	390 800	9 297 400
1963	7 282 400	940 100	8 222 500	762 700	399 300	9 384 500
1964	7 282 400	940 000	8 222 400	715 300	374 500	9 312 200
1965	7 282 400	940 000	8 222 400	667 900	349 700	9 240 000
1966	7 282 400	940 000	8 222 400	620 500	324 900	9 167 800
1967	7 282 400	940 000	8 222 400	573 100	300 100	9 095 600
1968	7 282 400	940 000	8 222 400	525 700	275 300	9 023 400
1969	7 282 400	940 000	8 222 400	478 300	250 500	8 951 200
1970	7 281 500	940 000	8 221 500	430 900	225 700	8 878 100
1971	7 281 400	940 000	8 221 400	383 500	200 800	8 805 700
1972	7 303 400	940 000	8 243 400	366 200	191 700	8 801 300
1973	7 359 800	940 000	8 299 800	346 600	181 500	8 827 900
1974	6 500 300	830 600	7 330 900	290 700	152 200	7 773 800
1975	3 796 900	691 000	4 487 900	240 300	125 800	4 854 000
1976	3 104 200	599 000	3 703 200	198 400	103 900	4 005 500
1977	2 813 700	518 700	3 332 400	175 600	91 900	3 599 900
1978	2 446 500	427 800	2 874 300	154 900	81 100	3 110 300
1979	2 141 400	373 700	2 515 100	124 100	65 000	2 704 200
1980	1 836 000	303 700	2 139 700	106 200	55 600	2 301 500
1981	1 632 800	256 600	1 889 400	104 800	54 900	2 049 100
1982	1 465 800	213 000	1 678 800	92 600	48 500	1 819 900
1983	1 075 100	130 600	1 205 700	76 700	40 100	1 322 500
1984	816 700	109 500	926 200	59 300	31 000	1 016 500
1985	698 000	90 700	788 700	44 700	23 400	856 800
1986	662 400	82 600	745 000	32 700	17 100	794 800
1987	624 500	74 100	698 600	21 700	11 400	731 700
1988	393 000	47 000	440 000	11 800	6 200	458 000
1989	372 600	41 800	414 400	5 600	2 900	422 900
TOTALS	$125 019 600	$17 010 700	$142 030 300	$ 9 143 200	$ 4 787 400	$155 960 900

(1) At 2.2548¢ per W.I. MCF (Equivalent to 2.3¢ @ 15.025#)

DOCKET NOS. G-12446 ET AL
EXHIBIT NO. X-16

Filed with Exrs. Certification dated JUN 29 1962

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 2

(B) Total Cost of Gas per Exhibit X-4	(C) Add La. Severance Tax on W.I. Gas (1)	(D) Total Cost of Gas Before Return & F.I.T.	(E) Add Return at 6%	(F) Add Fed. Income Tax re. Return	(G) Total Cost of Service	(H) Cost of Service per MCF @ 14.73#	(I) Cost of Service per MCF @ 15.025#
$ 7 216 600	$ 940 100	$ 8 156 700	$ 786 100	$ 411 600	$ 9 354 400	22.44¢	22.89¢
7 220 200	940 100	8 160 300	746 300	390 800	9 297 400	22.30	22.75
7 282 400	940 100	8 222 500	762 700	399 300	9 384 500	22.51	22.96
7 282 400	940 000	8 222 400	715 300	374 500	9 312 200	22.34	22.79
7 282 400	940 000	8 222 400	667 900	349 700	9 240 000	22.16	22.60
7 282 400	940 000	8 222 400	620 500	324 900	9 167 800	21.99	22.43
7 282 400	940 000	8 222 400	573 100	300 100	9 095 600	21.82	22.26
7 282 400	940 000	8 222 400	525 700	275 300	9 023 400	21.64	22.07
7 282 400	940 000	8 222 400	478 300	250 500	8 951 200	21.47	21.90
7 281 500	940 000	8 221 500	430 900	225 700	8 878 100	21.30	21.73
7 281 400	940 000	8 221 400	383 500	200 800	8 805 700	21.12	21.54
7 303 400	940 000	8 243 400	366 200	191 700	8 801 300	21.11	21.53
7 359 800	940 000	8 299 800	346 600	181 500	8 827 900	21.17	21.59
6 500 300	830 600	7 330 900	290 700	152 200	7 773 800	21.10	21.52
3 796 900	691 000	4 487 900	240 300	125 800	4 854 000	15.84	16.16
3 104 200	599 000	3 703 200	198 400	103 900	4 005 500	15.08	15.38
2 813 700	518 700	3 332 400	175 600	91 900	3 599 900	15.65	15.96
2 446 500	427 800	2 874 300	154 900	81 100	3 110 300	16.39	16.72
2 141 400	373 700	2 515 100	124 100	65 000	2 704 200	16.32	16.65
1 836 000	303 700	2 139 700	106 200	55 600	2 301 500	17.09	17.43
1 632 800	256 600	1 889 400	104 800	54 900	2 049 100	18.00	18.36
1 465 800	213 000	1 678 800	92 600	48 500	1 819 900	19.26	19.65
1 075 100	130 600	1 205 700	76 700	40 100	1 322 500	22.84	23.30
816 700	109 500	926 200	59 300	31 000	1 016 500	20.94	21.36
698 000	90 700	788 700	44 700	23 400	856 800	21.31	21.74
662 400	82 600	745 000	32 700	17 100	794 800	21.70	22.13
624 500	74 100	698 600	21 700	11 400	731 700	22.27	22.72
393 000	47 000	440 000	11 800	6 200	458 000	21.97	22.41
372 600	41 800	414 400	5 600	2 900	422 900	22.80	23.26
$125 019 600	$17 010 700	$142 030 300	$ 9 143 200	$ 4 787 400	$155 960 900	20.67	21.09

(1) 2.3¢ @ 15.025#)

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 3

(A) YEAR	(B) TOTAL COST OF GAS PER EXHIBIT X-4	(C) ADD: LA. SEVERANCE TAX ON W.I. GAS (1)	(D) ADD: ROYALTY AND OUTSIDE INT. GAS (2)	(E) TOTAL COST OF GAS BEFORE RETURN & F.I.T.	(F) ADD: RETURN AT 6%	(G) ADD: FED. INCOME TAX RE RETURN	(H) TOTAL COST OF SERVICE
1961	$ 7 216 600	$ 940 100	$ 2 084 700	$ 10 247 400	$ 786 100	$ 411 600	$ 11 439 100
1962	7 220 200	940 100	2 084 700	10 245 000	746 300	390 800	11 382 100
1963	7 282 400	940 100	2 084 700	10 307 200	762 700	399 300	11 469 200
1964	7 282 400	940 000	2 084 700	10 307 100	715 300	374 500	11 396 900
1965	7 282 400	940 000	2 084 700	10 307 100	667 900	349 700	11 324 700
1966	7 282 400	940 000	2 084 700	10 307 100	620 500	324 900	11 252 500
1967	7 282 400	940 000	2 084 700	10 307 100	573 100	300 100	11 180 300
1968	7 282 400	940 000	2 084 700	10 307 100	525 700	275 300	11 108 100
1969	7 282 400	940 000	2 084 700	10 307 100	478 300	250 500	11 035 900
1970	7 281 500	940 000	2 084 700	10 306 200	430 900	225 700	10 962 800
1971	7 281 400	940 000	2 084 700	10 306 100	383 500	200 800	10 890 400
1972	7 303 400	940 000	2 084 700	10 328 100	366 200	191 700	10 886 000
1973	7 359 800	940 000	2 084 700	10 384 500	346 600	181 500	10 912 600
1974	6 500 300	830 600	1 841 900	9 172 800	290 700	152 200	9 615 700
1975	3 796 900	691 000	1 532 100	6 020 000	240 300	125 800	6 386 100
1976	3 104 200	599 000	1 328 000	5 031 200	198 400	103 900	5 333 500
1977	2 813 700	518 700	1 150 100	4 482 500	175 600	91 900	4 750 000
1978	2 446 500	427 800	948 700	3 823 000	154 900	81 100	4 059 600
1979	2 141 400	373 700	828 600	3 343 700	124 100	65 000	3 532 800
1980	1 836 000	303 700	673 300	2 813 000	106 200	55 600	2 974 800
1981	1 632 800	256 600	569 000	2 458 400	104 800	54 900	2 618 100
1982	1 465 800	213 000	472 400	2 151 200	92 600	48 500	2 292 300
1983	1 075 100	130 600	289 600	1 495 300	76 700	40 100	1 612 100
1984	816 700	109 500	242 800	1 169 000	59 300	31 000	1 259 300
1985	698 000	90 780	201 000	989 700	44 700	23 400	1 057 800
1986	662 400	82 600	183 200	928 200	32 700	17 100	978 000
1987	624 500	74 100	164 400	863 000	21 700	11 400	896 100
1988	393 000	47 000	104 100	544 100	11 800	6 200	562 100
1989	372 600	41 800	92 600	507 000	5 600	2 900	515 500
TOTALS	$125 019 600	$17 010 700	$37 722 900	$179 753 200	$ 9 143 200	$ 4 787 400	$193 683 800

(1) At 2.2548¢ per W.I. MCF (Equivalent to 2.3¢ @ 15.025#).

(2) At 22.1563¢ per MCF of Royalty and Outside Interest Gas (Equivalent to 22.6¢ @ 15.025#)

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 3

Filed with Exs. Certification JUN 29 1962

DOCKET NOS. G-12446 ET AL
EXHIBIT NO. X-17

(B) Total Cost of Gas per Exhibit X-4	(C) ADD: La. Severance Tax on W.I. Gas (1)	(D) ADD: Royalty and Outside Int. Gas (2)	(E) Total Cost of Gas before Return & F.I.T.	(F) ADD: Return at 6%	(G) ADD: Fed. Income Tax re. Return	(H) Total Cost of Service	(I) Cost of Service per MCF @ 14.73#	(J) Cost of Service per MCF @ 15.025#
$ 7 216 600	$ 940 100	$ 2 084 700	$ 10 241 400	$ 786 100	$ 411 600	$ 11 439 100	22.39¢	22.84¢
7 220 200	940 100	2 084 700	10 245 000	746 300	390 800	11 382 100	22.27¢	22.72¢
7 282 400	940 100	2 084 700	10 307 200	762 700	399 300	11 469 200	22.44¢	22.89¢
7 282 400	940 000	2 084 700	10 307 100	715 300	374 500	11 396 900	22.30¢	22.75¢
7 282 400	940 000	2 084 700	10 307 100	667 900	349 700	11 324 700	22.16¢	22.60¢
7 282 400	940 000	2 084 700	10 307 100	620 500	324 900	11 252 500	22.02¢	22.46¢
7 282 400	940 000	2 084 700	10 307 100	573 100	300 100	11 180 300	21.88¢	22.32¢
7 282 400	940 000	2 084 700	10 307 100	525 700	275 300	11 108 100	21.74¢	22.18¢
7 282 400	940 000	2 084 700	10 307 100	478 300	250 500	11 035 900	21.60¢	22.03¢
7 281 500	940 000	2 084 700	10 306 200	430 900	225 700	10 962 800	21.45¢	21.88¢
7 281 400	940 000	2 084 700	10 306 100	383 500	200 800	10 890 400	21.31¢	21.74¢
7 303 400	940 000	2 084 700	10 328 100	366 200	191 700	10 886 000	21.30¢	21.73¢
7 359 800	940 000	2 084 700	10 384 500	346 600	181 500	10 912 600	21.36¢	21.79¢
6 500 300	830 600	1 841 900	9 172 800	290 700	152 200	9 615 700	21.20¢	21.73¢
3 796 900	691 000	1 532 100	6 020 000	240 300	125 800	6 386 100	17.00¢	17.34¢
3 104 200	599 000	1 328 000	5 031 200	198 400	103 900	5 333 500	16.38¢	16.71¢
2 813 700	518 700	1 150 100	4 482 500	175 600	91 900	4 750 000	16.85¢	17.19¢
2 446 500	427 800	948 700	3 823 000	154 900	81 100	4 059 000	17.46¢	17.81¢
2 141 400	373 700	828 600	3 343 700	124 100	65 000	3 532 800	17.39¢	17.74¢
1 836 000	303 700	673 300	2 813 000	106 200	55 600	2 974 800	18.02¢	18.38¢
1 632 800	256 600	569 000	2 458 400	104 800	54 900	2 618 100	18.77¢	19.15¢
1 465 800	213 000	472 400	2 151 200	92 600	48 500	2 292 300	19.80¢	20.20¢
1 075 100	130 600	289 600	1 495 300	76 700	40 100	1 612 100	22.71¢	23.16¢
816 700	109 500	242 800	1 169 000	59 300	31 000	1 259 300	21.16¢	21.58¢
698 000	90 700	201 000	989 700	44 700	23 400	1 057 800	21.47¢	21.90¢
662 400	82 600	183 200	928 200	32 700	17 100	978 000	21.78¢	22.22¢
624 500	74 100	164 400	863 000	21 700	11 400	896 100	22.25¢	22.70¢
393 000	47 000	104 100	544 100	11 800	6 200	562 100	22.00¢	22.44¢
372 600	41 800	92 600	507 000	5 600	2 900	515 500	22.68¢	23.13¢
$125 019 600	$17 010 700	$37 722 900	$179 753 200	$ 9 143 200	$ 4 787 400	$193 683 800	28.95¢	21.37¢

3¢ (@ 15.025#)

Interest Gas (Equivalent To 22.6¢ @ 15.025#)

X-18

TEXAS EASTERN TRANSMISSION CORPORATION
COST OF SERVICE STUDY
RAYNE FIELD
CASE 4

Filed with
dated J

(A) YEAR	(B) TOTAL COST OF GAS PER EXHIBIT X-4	(C) ADD: LA. SEVERANCE TAX ON W.I. GAS	(D) ADD: ROYALTY AND OUTSIDE INT. GAS	(E) TOTAL COST OF GAS BEFORE RETURN & F.I.T.	(F) ADD: RETURN AT 6% ON NET PLANT	(G) ADD: FED. INCOME TAX RE RETURN	(F) ADD: RETURN AT 6% ON O.D.D.	(H) ADD: FED. INCOME TAX RE RETURN
1961	$ 7,216,600	$ 940,100	$ 2,084,700	$ 10,241,400	$ 786,100	$ 411,600	$ 28,200	$ 14,800
1962	7,220,200	940,100	2,084,700	10,245,000	746,300	[illegible]0,800	134,200	70,300
1963	7,282,400	940,100	2,084,700	10,307,200	762,700	399,300	240,100	125,700
1964	7,282,400	940,000	2,084,700	10,307,100	715,300	374,500	345,800	181,100
1965	7,282,400	940,000	2,084,700	10,307,100	667,900	349,700	451,400	236,400
1966	7,282,400	940,000	2,084,700	10,307,100	620,500	324,900	556,900	291,600
1967	7,282,400	940,000	2,084,700	10,307,100	573,100	300,100	662,900	347,100
1968	7,282,400	940,000	2,084,700	10,307,100	525,700	275,300	768,600	402,400
1969	7,282,400	940,000	2,084,700	10,307,100	478,300	250,500	874,200	457,700
1970	7,281,500	940,000	2,084,700	10,306,200	430,900	225,700	979,700	513,000
1971	7,281,400	940,000	2,084,700	10,306,100	383,500	200,800	1,085,500	568,400
1972	7,303,400	940,000	2,084,700	10,328,100	366,200	191,700	1,191,100	623,600
1973	7,359,800	940,000	2,084,700	10,384,500	346,600	181,500	1,291,000	676,000
1974	6,500,300	830,600	1,841,900	9,172,800	290,700	152,200	1,384,600	725,000
1975	3,796,900	691,000	1,532,100	6,020,000	240,300	125,800	1,520,700	796,300
1976	3,104,200	599,000	1,328,000	5,031,200	198,400	103,900	1,354,500	709,200
1977	2,813,700	518,700	1,150,100	4,482,500	175,600	91,900	1,106,300	579,200
1978	2,446,500	427,800	948,700	3,823,000	154,900	81,100	891,300	466,700
1979	2,141,400	373,700	828,600	3,348,700	124,100	65,000	714,100	373,900
1980	1,836,000	303,700	673,300	2,813,000	106,200	55,600	559,200	292,800
1981	1,632,800	256,600	569,000	2,458,400	104,800	54,900	433,400	226,900
1982	1,465,800	213,000	472,400	2,151,200	92,600	48,500	327,100	171,300
1983	1,075,100	130,600	289,600	1,495,300	76,700	40,100	238,800	125,000
1984	816,700	109,500	242,800	1,169,000	59,300	31,000	184,700	96,700
1985	698,000	90,700	201,000	989,700	44,700	23,400	139,300	73,000
1986	662,400	82,600	183,200	928,200	32,700	17,100	101,800	53,300
1987	624,500	74,100	164,400	863,000	21,700	11,400	67,500	35,400
1988	393,000	47,000	104,100	544,100	11,800	6,200	36,800	19,300
1989	372,600	41,800	92,600	507,000	5,600	2,900	17,400	8,800
TOTAL	$125,019,600	$17,010,700	$37,722,900	$179,753,200	$9,143,200	$4,787,400	$17,687,100	$9,260,900

Hearing Exhibit X-18 (3822)

DOCKET NOS. G-12446 ET AL

EXHIBIT No. X-18

Filed with Exrs. Certification dated JUN 29 1962

TEXAS EASTERN TRANSMISSION CORPORATION

COST OF SERVICE STUDY
RAYNE FIELD
CASE 4

(B)	(C)	(D)	(E)	(F)	(G)	(F)	(H)	(I)	(J)	(K)
	ADD			ADD		ADD			Cost of Service per MCF	
…tal Cost of …as per …hibit X-4	La. Severance Tax on W.I. Gas	Royalty and Outside Int. Gas	Total Cost of Gas Before Return & F.I.T.	Return at 6% on Net Plant	Fed. Income Tax re Return	Return at 6% on O.D.D.	Fed. Income Tax re Return	Total Cost of Service	@ 14.73#	@ 15.025#
7 216 600	$ 940 100	$ 2 084 700	$ 10 241 400	$ 786 100	$ 411 600	$ 28 200	$ 14 800	$ 11 482 100	22.47¢	22.92
7 220 200	940 100	2 084 700	10 245 000	746 300	390 800	134 200	70 300	11 586 600	22.67	23.12
7 282 400	940 100	2 084 700	10 307 200	762 700	399 300	240 100	125 700	11 835 000	23.16	23.62
7 282 400	940 000	2 084 700	10 307 100	715 300	374 500	345 800	181 100	11 923 800	23.33	23.80
7 282 400	940 000	2 084 700	10 307 100	667 900	349 700	451 400	236 400	12 012 500	23.51	23.98
7 282 400	940 000	2 084 700	10 307 100	620 500	324 900	556 900	291 600	12 101 000	23.68	24.15
7 282 400	940 000	2 084 700	10 307 100	573 100	300 100	662 900	347 100	12 190 300	23.86	24.34
7 282 400	940 000	2 084 700	10 307 100	525 700	275 300	768 600	402 400	12 279 100	24.03	24.51
7 282 400	940 000	2 084 700	10 307 100	478 300	250 500	874 200	457 700	12 367 800	24.20	24.68
7 281 500	940 000	2 084 700	10 306 200	430 900	225 700	979 700	513 000	12 455 500	24.37	24.86
7 287 400	940 000	2 084 700	10 306 100	383 500	200 800	1 085 500	568 400	12 544 300	24.55	25.04
7 303 400	940 000	2 084 700	10 328 100	366 200	191 700	1 191 100	623 600	12 700 700	24.85	25.35
7 359 800	940 000	2 084 700	10 384 500	346 600	181 500	1 291 000	676 000	12 879 600	25.20	25.70
6 500 300	830 600	1 841 900	9 172 800	290 700	152 200	1 384 600	725 000	11 725 300	25.97	26.49
3 796 900	691 000	1 532 100	6 020 000	240 300	125 800	1 520 700	796 300	8 703 100	23.17	23.63
3 104 200	599 000	1 328 000	5 031 200	198 400	103 900	1 354 500	709 200	7 397 200	22.72	23.18
2 863 700	518 700	1 150 100	4 482 500	175 600	91 900	1 106 300	579 200	6 435 500	22.83	23.29
2 446 500	427 800	948 700	3 823 000	154 900	81 100	891 300	466 700	5 417 000	23.29	23.76
2 141 400	373 700	828 600	3 343 700	124 100	65 000	714 100	373 900	4 620 800	22.75	23.21
1 836 000	303 700	673 300	2 813 000	106 200	55 600	559 200	292 800	3 826 800	23.19	23.65
1 632 800	256 600	569 000	2 458 400	104 800	54 900	433 400	226 900	3 278 400	23.50	23.97
1 465 800	213 000	472 400	2 151 200	92 600	48 500	327 100	171 300	2 790 700	24.10	24.58
1 075 100	130 600	289 600	1 495 300	76 700	40 100	238 800	125 000	1 975 900	27.84	28.40
816 700	109 500	242 800	1 169 000	59 300	31 000	184 700	96 700	1 540 700	25.89	26.41
698 000	90 700	201 000	989 700	44 700	23 400	139 300	73 000	1 270 100	25.77	26.29
662 400	82 600	183 200	928 200	32 700	17 100	101 800	53 300	1 133 100	25.24	25.75
624 500	74 100	164 400	863 000	21 700	11 400	67 500	35 400	999 000	24.80	25.30
393 000	47 000	104 100	544 100	11 800	6 200	36 800	19 300	618 200	24.20	24.68
372 600	41 800	92 600	507 000	5 600	2 900	17 400	8 800	541 700	23.83	24.31
…5 019 600	$17 010 700	$37 722 900	$179 753 200	$9 143 200	$4 787 400	$17 687 100	$9 260 900	$220 631 800	23.86¢	24.34¢

3823

Hearing Ex. No. X-19

MANAGEMENT AGREEMENT

RAYNE FIELD, ACADIA PARISH, LOUISIANA

BETWEEN

CONTINENTL OIL COMPANY

AND

LOUISIANA GAS CORPORATION

Dated July 27, 1959

3824

MANAGEMENT AGREEMENT

This Management Agreement made and entered into by and between Continental Oil Company, a Delaware corporation, herein called "Continental", and Louisiana Gas Corporation, a Delaware corporation, herein called "Louisiana Gas",

WITNESSETH:

Whereas, by Assignment and Conveyance, Sun Oil Company, a New Jersey corporation, M. H. Marr, General Crude Oil Company, a Delaware corporation, and Continental Oil Comapny, a Delaware corporation, herein called "Sun et al", assigned and conveyed certain leasehold interests to Louisiana Gas Corporation, a Delaware corporation, a copy of the Assignment and Conveyance being annexed hereto as Exhibit "1" and made a part hereof for full particulars as to the leasehold interests conveyed, the terms, provisions and limitations thereof; and

Whereas, Continental is a corporation engaged primarily in the business of exploring for and producing oil and gas;

and its experience and capabilites in connection with the operation of producing properties are recognized by Louisiana Gas; and in particular, Continental, as Operator for Sun et al, has heretofore drilled and operated high-pressure gas wells completed in the particular leasehold interests covered by the Assignment and Conveyance and has thus supervised the development of the same and is throughly familiar with the engineering and operating problems relating thereto; and

WHEREAS, Continental has the personnel and facilities necessary to operate such properties safely and efficiently during the term of this agreement and is willing to operate same as the managing agent of Louisiana Gas; and

WHEREAS, Louisiana Gas has had no expeience in operating gas properties in the Rayne Field or in the vicinity thereof, and due to extremely high pressure in the reservoirs and the hazards encounted by an inexperienced Operator, Louisiana Gas has acquired such leasehold interests from Sun et al with the inderstanding that it could obtain the experienced and capable management of such properties by Continental:

NOW THEREFORE, in consideration of the premises Continental and Louisiana Gas agree as follows:

1. AUTHORITIES AND DUTIES OF CONTINENTAL

In connection with the leasehold interests covered by the Assignment and Conveyance, annexed hereto as Exhibit "1", (said leasehold interests, insofar as assigned to Louisiana Gas, herein called "management area") Continental, as managing agent of Louisiana Gas and as the duly appointed and authorized representative of Louisiana Gas, shall perform, and agrees with Louisiana Gas that for the term of this agreement it will perform, as follows:

(a) Continental shall drill, develop, produce, rework, complete, recomplete, abandon, operate, maintain and manage all wells and well equipment, including secondary recovery and recycling equipment, now or hereafter located on the management area, as a prudent operator; provided, however, that no well shall be drilled, nor shall any existing well be deepened below the casing previously set therein without the consent of Louisiana Gas. Continental agrees to drill any well, (or to deepen

3825

any well below the casing previously set therein) upon the request of Louisiana Gas, providing that necessary permits can be obtained for such requested drilling or deepening and completion. The well location, projected depth and interval of completion on any drilling or deepening so requested by Louisiana Gas shall be specified by Louisiana Gas. Continental will furnish all labor, material and services required in the performance of its obligations under this agreement, it being understood that all wells drilled and equipment installed hereunder shall be and remain the property of Louisiana Gas.

(b) Except for the payment of royalties, overriding royalties, production payments and other burdens on production in connection with the management area, Continental (subject to the other provisions of this agreement) shall perform all duties and obligations, insofar as applicable to the management area, imposed or arising by virtue of the leases and other documents described in Exhibit "1" hereto attached, and other instruments now in existence affecting the management area, including all express and implied obligations thereunder.

(c) Insofar as legally permissible, Continental (subject to the other provisions of this agreement) shall perform all duties now or hereafter imposed upon Louisiana Gas as owner and operator of the management area by state law or by the regulations and orders of the Commissioner of Conservation of the State of Louisiana, or of any other Louisiana governmental agency or official having jurisdiction with respect to the management area and the wells now or hereafter drilled and the well equipment installed or located thereon.

(d) Subject to force majeure and to applicable laws and the regulations and orders of the Commissioner of Conservation of the State of Louisiana or other Louisiana governmental agency or official having jurisdiction, Continental (subject to the other provisions of this agreement) will do and perform all things which a prudent operator acting in consideration of sound economics and sound engineering practices would do and perform to so develop and operate the management area that, after adequate nominations by producers or purchasers of production, and previous takes of granted gas allowables to prevent reduction of nominated gas allowables because of failure to take, a minimum daily quantity of production equivalent to at least 150,000 MCF of gas at the wellhead during the two years commencing August 1, 1959, at least 191,000 MCF of gas at the wellhead during the period commencing August 1, 1961, through April 1, 1975, and at least 150,000 MCF of gas at the wellhead for the remaining term (a cubic foot of gas being the same as defined in the Assignment and Conveyance) will be available for delivery from the management area. In the discharge of the obligations herein undertaken

Continental shall (1) at its sole discretion determine the rate of production from any particular well that could be produced without injury to the well, pool or reservoir from which it is producing, and nothing herein contained shall be construed to require production at a greater rate; (2) at its sole discretion determine the maximum efficient rate of production from any pool or reservoir in the management area and shall not be required to produce such pool or reservoir at the rate which is in excess of the maximum efficient rate of withdrawal; and (3) never be required to rework a well or to perform any other operations hereunder when, as a prudent operator, it would determine that the produc-

tion from such well or operation would not be sufficient to bring a profit on such well to a lessee holding the oil and gas lease or leases on the tracts or unit on which the well is drilled.

(e) The particular delegation of authorities and duties expressed in this article shall not be construed as exclusive and restrictive, it being the intent of the parties that (subject to the other provisions of this agreement) Continental shall have the authority and duty to do and perform in its name as the managing agent, or in the name of Louisiana Gas, as the authorized representative of Louisiana Gas, all of the drilling, development and well control procedures that a prudent operator would exercise in developing the management area and bringing the production therefrom to the surface. Gathering, handling, separating, treating and storing of the production, the sale thereof and payment therefor shall not be included in this delegation of authority, such oper-

ating rights and duties to be performed by Louisiana Gas, its successors and assigns.

(f) Continental shall carry and pay for the following insurance coverages

(1) Workmen's compensation and employer's liability insurance in accordance with the laws of the State of Louisiana.

(2) Comprehensive general public liability insurance with bodily injury limits of not less than $25,000 any one person and $50,000 any one accident and with property damage limits of not less than $10,000 any one accident and $50,000 aggregate.

(3) Comprehensive automobile liability insurance with bodily injury limits of not less than $25,000 any one person and $50,000 any one accident and with a property damage limit of not less than $5,000 any one accident.

(4) Excess liability insurance of not less than $500,000 for any one occurrence to apply above the basic limits of items (2) and (3) above.

(5) Fire and extended coverage insurance to cover lease surface equipment in suitable amounts to be determined by Continental.

(g) Continental shall require all drilling contractors engaged in operations on or in connection with the management area to carry and pay for the following insurance coverages:

(1) Workmen's compensation and employer's liability insurance in accordance with the laws of the State of Louisiana.

(2) General public liability insurance with bodily injury limits of not less than $100,000 any one person and $300,000 any one accident and with a property damage limit of not less than $50,000 any one accident, aggregate $100,000.

(3) Automobile public liability insurance with bodily injury limits of not less than $100,000 any one person and $300,000 any one accident and with a property damage limit of not less than $10,000.

(4) Contractual liability insurance with bodily injury limits of not less than $100,000 any one person and $300,000 any one accident and with a property damage limit of not less than $50,000 any one accident, aggregate $100,000.

2. Responsibility for Expenditures

Continental shall pay all costs of drilling, developing and operating the management area during the term of this agreement, and pay all other costs and expenses of every kind and nature arising from, or based on, the discharge of its duties under Article 1, as well as taxes (except state, federal and other governmental income, excess profits, capital stock, corporate franchise taxes and taxes of a similar nature or equivalent in effect) levied on the ownership of the management area and equipment. It shall pay the expense of any litigation (except the expense of Louisiana Gas, its successors or assigns, in any litigation with Continental) resulting from its operations, or that of its contractors, servants, agents and employees, and shall keep the management area, wells and equipment free and clear of any lien or encumbrance arising from the discharge

of its duties, provided that Continental shall have the right to contest the validity of any claim or demand; but in any event, if all or any portion of the management area, wells or equipment should be seized under any legal process in connection with any such claim or demand, Continental shall cause the property seized to be released, or the seizure stayed within thirty days from the date of seizure or within five days before the date set for the sale of the property whichever is earlier, unless, after notice from Continental, Louisiana Gas advises that its interests will not be adversely affected by the continuance of such seizure. Claims against Louisiana Gas based on the ownership of the management area and operation thereof, insofar as they are within the limits of the operational authority delegated to Continental herein, shall be assumed and paid, or defended, by Continental.

The rights and duties of Continental under Article I are limited in that it has no control over or responsibility for the production from the management area after it reaches the first control point above the surface on each well; consequently the obligations thereafter accruing shall be those of Louisiana Gas, its successors and assigns. By way of illustration and not as all inclusive limitations, Louisiana Gas, its successors and assigns, shall be responsible for and pay all costs and expenses in connection with:

(a) The payment, non-payment or improper payment of any royalty, overriding royalty or production payment due with regard to actual production;

(b) Installation, maintenance, and operation of the gathering, processing and marketing facilities, except that Continental shall provide such well meters as may be required by the Commissioner of Conservation of the State of Louisiana;

(c) Taxes relating to the severance, production, gathering and marketing of the production from the management area; and

(d) Litigation and judgments relating to a claim or demand which Louisiana Gas is obligated to bear under (a), (b) and (c) above.

3. PAYMENT FOR SERVICES

As payment in full for the performance by Continental of its obligations hereunder, Louisiana Gas agrees to pay Continental at its offices in Houston, Harris County, Texas, on or before the 25th day of each calendar month (beginning with the month of August, 1959), or within fifteen (15) days after receipt of invoice with detailed statement attached, whichever is the later date, a sum equal to all costs and expenses incurred by Continental in connection with performance of its obligations hereunder during the pre-

3828

ceding calendar month (computed in accordance with Exhibit "2" hereto attached, to the extent same does not conflict herewith) plus a management fee of Four Thousand Dollars ($4,000.00) per month. Continental shall not be paid or reimbursed any sums expended by it in defending, settling, or paying any liability that may be incurred under Article 5(h) hereof.

4. TERM

This agreement shall be effective as of the 27th day of July, 1959, and shall (except as hereinafter provided) continue in force, and the obligations thereof shall remain in effect, as to each lease respectively for so long as said lease (and any renewal or extension thereof, including new leases

on the mineral interests covered thereby, or a part thereof, or an interest therein) remains in effect; or until the production payment reserved by Sun et al in the Assignment and Conveyance terminates, whichever is earlier; and the rights of Louisiana Gas hereunder may be assigned together with any assignment of the leasehold interests covered by the Assignment and Conveyance, the assignee in such instance taking subject to the provisions hereof.

At the option of Continental, this agreement may be terminated without advance notice,

(a) If Louisiana Gas transfers or assigns any interest in the management area without the prior approval of Continental, or if any successor or assign of Louisiana Gas, or a successive assign, makes a transfer without the prior approval of Continental;

(b) If Louisiana Gas, or a successor, fails to pay Continental any fee and charge, except as to any item on a statement that is the subject of a bona fide dispute, for the service herein undertaken within thirty (30) days after receipt of invoice and statement and the continuance of such failure for a period of fifteen (15) days after written notice of default;

(c) As to any particular tract or lease in the management area when,

(1) as a prudent operator, Continental recommends a release thereof to the extent necessary to satisfy claims and demands of a lessor, in lieu of complying with such claim or demand, and Continental tenders an assignment of its reserved production payment in such tract or lease to Louisiana Gas, or

(2) the production from a lease on the management area is no longer in paying quantities to the lessor and lessee, or

(3) there is drainage of a lease that Louisiana Gas does not elect to protect by drilling an offset well.

At the option of Louisiana Gas, this agreement may be terminated as to any particular tract or lease in the management area when Louisiana Gas (i) tenders to Sun et al, for concurrence, a release thereof; or (ii) joins Sun et al, in a release thereof; or (iii) accepts an assignment from Sun et al of their reserved rights in such tract or lease; or (iv) tenders a reassignment of its interest therein to Sun et al. The events giving rise to the right of Louisiana Gas to terminate as to a particular tract or lease as provided above

shall not be considered a transfer or assignment requiring the prior approval of Continental under subparagraph (a) of this Article 4.

5. General

(a). No secondary recovery program or recycling operation shall be employed or commenced by Continental which would have the effect of diminishing the production available for delivery from the management area below the volume of gas per day at the wellhead (as set out in subparagraph [d] of Article 1 hereof) unless such secondary recovery program or recycling operation is required by order, rule or regulation of the Commissioner of Conservation of the State of Louisiana or other State of Louisiana regulatory official or body having jurisdiction, or such

secondary recovery or recycling operation is given the prior written approval of Louisiana Gas.

(b) Each party agrees promptly to furnish the other with copies of all claims and demands and of all notices and citations in suits and proceedings which are received by it and relate to the management area and the respective responsibilities of the parties under this agreement. Each party further agrees to keep the other fully advised currently of all developments in connection with the foregoing, and to consult freely with the other relating thereto and to cooperate fully in the defense of the same.

(c) In the event a claim, demand or action is presented to either party that encompasses within its allegations and scope claimed default in obligations undertaken by Continental pursuant to this agreement and obligations relating to the gathering, handling, processing, treating, storing of production, or payment to the owners thereof which is the obligation of Louisiana Gas, the parties shall agree on a mutually satisfactory counsel and other representatives to properly defend the claim and the cost of such counsel and other representatives shall be shared equally. In the event of adverse judgment the burden of the judgment shall be that of the party who has the burden under the terms of this agreement.

(d) This agreement is intended to vest in Continental the authority to file, in the name of Continental, or Louisiana Gas, all notices, applications, logs, requests, documents or similar reports and forms required by state law, rule, regulation or order in connection with the duties undertaken including the rendition of lease and related equipment now located or hereafter placed by Continental on the management area for ad valorem taxes. Filings and reports made by Continental, even though in the name of Continental, and regardless of the capacity shown, shall

be reports by and of Louisiana Gas. Should rules or regulations require that reports be made in the name of the owner and/or operator of the lease, any employee of Continental who would be authorized to make such report in the name of Continental in the course of its normal business in operating its properties is expressly authorized to make such report as the employee of and in the name of Louisiana Gas.

(e) Hearings before the Commissioner of Conservation for the State of Louisiana regarding the unitization of the management area and the drilling and development thereof shall be conducted by Continental if requested by Continental and by Louisiana Gas if requested by Louisiana Gas. Nominations for production shall be made by Louisiana Gas or the purchaser of the gas and any hearings regarding gathering, processing, and handling of such production shall be conducted by Louisiana Gas. Each party shall give the other advance notice of any proposed application for a hearing relating to the

3830

management area or the production therefrom, and will exert all reasonable effort to secure approval of the other party as to the application and evidence to be presented to support the proposal. In the event the parties cannot mutually agree, the party initially proposing the application shall proceed with same and the other party shall have the right to appear at such hearing and present any evidence it deems necessary and advisable.

(f) At least ten (10) days prior to the date nominations for production are filed by Louisiana Gas or the purchaser of the gas, notice of the proposed nomination for that part of the Rayne Field within the management area shall be given to Continental. In the event Continental does not believe the management area (produced as provided under

subparagraph [d] of Article 1 hereof) will be capable of producing at a rate sufficient to deliver the proposed nominated quantities, it will advise Louisiana Gas or the purchaser, within five (5) days after receipt of the notice, of the estimated deliverable gas; and if Continental does not reply to such notice, it shall be deemed that, in the opinion of Continental, the proposed nominated quantities can be so produced. Louisiana Gas or the purchaser shall notify Continental from time to time of the rate at which it elects to take production from the management area.

(g) Force majeure is defined to mean acts of God, inability to obtain material and equipment, strikes, riots, war and other causes (except financial) beyond the control of any of the parties hereto, and neither of the parties shall be liable to the other party for failure to perform or for delay in the performance of any of the terms or provisions hereof, if such failure to pay or delay is the result of force majeure. The party prevented from performing its obligations hereunder by reason of force majeure shall give the other party prompt notice of the force majeure and prompt notice when the force majeure is removed.

(h) If not otherwise limited and restricted herein, the liability and responsibility hereunder of Continental, its employees, agents, servants and assigns, to Louisiana Gas is expressly limited and restricted to and shall be the following:

(1) Liability of Louisiana Gas as Lessee to Lessors and royalty owners and liability of Louisiana Gas to overriding royalty owners and production payment owners;

(2) Liability of Louisiana Gas as Grantee under the assignment and Conveyance by Sun et al, annexed hereto as Exhibit "1";

(3) Liability for personal injury and property damage;

(4) The $12,420,500.00 cash consideration paid by Louisiana Gas for the Assignment and Conveyance, to the extent that the breach of Continental's obligations herein undertaken causes the volume of gas (after removal of condensate) capable of being economically produced from the management area to be less than 783,499,000,000 cubic feet of gas attributable to the net working interest acquired by Louisiana Gas under the Assignment and Conveyance from Sun et al; and the measure of damages in this event will be the volumes of gas lost valued at 20.7¢ per MCF, or the amount of the cash consideration paid by Louisiana Gas to Sun et al for the Assignment and Conveyance, whichever is the lesser;

(5) Losses incurred by Louisiana Gas by reason of the failure of Continental to release or stay a seizure as required under Article 2 hereof.

The entry of final judgment, discharge or settlement of a liability of Louisiana Gas under (1), (2) or (3) above shall be determinative of Continental's liability to pay same in full, together with its expense of litigation and settlement relating thereto, provided that Continental has been afforded notice and opportunity to defend same. In addition to the foregoing, Louisiana Gas shall have the right to enforce specific performance of the obligations of Continental hereunder.

(i) Under no circumstances shall Continental, is employees, servants or agents, be or become "employees" of Louisiana Gas, its successors or assigns.

(j) All notices, reports, and other communications required hereunder shall be deemed to have been properly given or delivered when delivered personally or when de-

livered by registered or certified mail, with all postage and charges fully prepaid, addressed to the parties hereto respectively as follows:

Continental Oil Company
Attention: Mr. O. L. Fisher
P. O. Box 2197
Houston 1, Texas

Louisiana Gas Corporation
Attention: Mr. Campbell A. Griffin
11th Floor—Esperson Building
Houston 2, Texas

Each party hereto shall have the right to change its address for all purposes by notifying the other party in writing.

In Testimony Whereof this instrument is executed in multiple originals, this 27th day of July, 1959.

Witnesses:

Buford Koehler
Edith Needham

Continental Oil Company
By O. L. Fisher
Vice President

C. R. Ebersole
Ann Vinson

Louisiana Gas Corporation
By Campbell A. Griffin
President

3832

The State of Texas
County of Harris

On this 27th day of July, 1959, before me, a Notary Public, appeared O. L. Fisher, to me personally known,

who being by me duly sworn, did say that he is Vice President of Continental Oil Company, a corporation, and that the foregoing instrument was signed on behalf of the said corporation by authority of its Board of Directors, and the said O. L. Fisher acknowledged said instrument to be the free act and deed of said corporation.

Witness my official signature and seal as such Notary Public on the day, month and year first above written.

HELEN P. WATERMAN
Helen P. Waterman
Notary Public in and for
Harris County, Texas

[Notarial Seal]

The State of Texas
County of Harris

On this 27th day of July, 1959, before me, a Notary Public, personally appeared Campbell A. Griffin, to me personally known, who being by me duly sworn, did say that he is President of Louisiana Gas Corporation, a corporation, and that the foregoing instrument was signed on beahlf of said corporation by authority of its Board of Directors, and the said Campbell A. Griffin acknowledged said instrument to be the free act and deed of said corporation.

Witness my official signature and seal as such Notary Public on the day, month and year first above written.

SARAH C. BYRNE
Sarah C. Byrne
Notary Public in and for
Harris County, Texas

[Notarial Seal]

3833

Exhibit 1

Assignment and Conveyance

3834

EXHIBIT "2"

Attached to and made a part of Management Agreement between Continental Oil Company and Louisiana Gas Corporation dated July 27, 1959.

ACCOUNTING PROCEDURE

I. General Provisions

1. *Payments*

Louisiana Gas Corporation shall pay all bills on or before the 25th day of the calendar month during which they are received or within fifteen (15) days after receipt thereof, whichever is the later date. If payment is not made within such time, the unpaid balance shall bear interest at the rate of six per cent (6%) per annum until paid.

2. *Audits*

Payment of any bills shall not prejudice the right of Louisiana Gas Corporation, or its representatives, to protest or question the correctness thereof. All statements rendered to Louisiana Gas Corporation, or its representatives, by Continental Oil Company during any calendar year shall be conclusively presumed to be true and correct after twenty-four months following the close of any such calendar year, unless within said twenty-four months' period Louisiana Gas Corporation, or its representatives, takes written exception thereto and makes claim on Continental Oil Company for adjustment. Failure on the part of Louisiana Gas Corporation or its representatives to

make claim on Continental Oil Company for adjustment within such period shall establish the correctness thereof and preclude the filing of exceptions thereto or the making of claims for adjustment thereon. Louisiana Gas Corporation, or its representatives, shall have the right to audit Continental Oil Company's accounts and records relating to the accounting hereunder at any time, but in any event within twenty-four months next following the close of any calendar year. Louisiana Gas, or its representatives, shall have six months next following the examination of Continental's records within which to take written exception to and make any and all claims on Continental. The provisions of this paragraph shall not prevent adjustments resulting from physical inventory of property as provided in Section VI, Inventories, hereof.

II. DEVELOPMENT AND OPERATING CHARGES

Subject to limitations hereinafter prescribed, Continental shall charge Louisiana Gas with the following:

1. *Labor*

A. Salaries and wages of Continental's employees directly engaged on the mangament area in the development, maintenance, and operation thereof, including salaries or wages paid to geologists and other employees who are temporarily assigned to and directly employed on the management area.

B. Continental's cost of holiday, vacation, sickness and disability benefits, and other customary allowances applicable to the salaries and wages chargeable under Subparagraph 1 A and Paragraph 10 of this Section II. Costs under this Subpara-

3835

graph 1 B may be charged on a "when and as paid basis" or by "percentage assessment" on the amount of salaries

and wages chargeable under Subparagraph 1 A and Paragraph 10 of this Section II. If percentage assessment is used, the rate shall be based on Continental's cost experience.

C. Costs of expenditures or contributions made pursuant to assessments imposed by governmental authority which are applicable to Continental's labor cost of salaries and wages as provided under Subparagraphs 1 A, 1 B, and Paragraph 10 of this Section II.

2. *Employee Benefits*

Continental's current cost of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Continental's labor cost, provided that the total of such charges shall not exceed ten per cent (10%) of Continental's labor costs as provided in Subparagraphs A and B of Paragraph 1 of this Section II and in Paragraph 10 of this Section II.

3. *Material*

Material, equipment, and supplies purchased by Continental, for use on the management area. So far as it is reasonably practical and consistent with efficient and economical operation, only such material shall be purchased for or transferred to the management area as required for immediate use, and the accumulation of surplus stocks shall be avoided.

4. *Transportation*

Transportation of employees, equipment, material, and supplies necessary for the development, maintenance, and operation of the management area subject to the following limitations:

A. If material is moved to the management area from vendor's or from Continental's warehouse or other properties, no charge shall be made to the management area for a distance greater than the distance from the nearest reliable supply store or railway receiving point where such material is available, except by special agreement with Louisiana Gas.

B. If surplus material is moved to Continental's warehouse or other storage point, no charge shall be made to the management area for a distance greater than the distance from the nearest reliable supply store or railway receiving point, except by special agreement with Louisiana Gas. No charge shall be made to the management area for moving material to other properties belonging to Continental, except by special agreement with Louisiana Gas.

5. *Service*

A. Outside Services:

The cost of contract services and utilities procured from outside sources.

B. Use of Continental's Equipment and Facilities:

Use of and service by Continental's exclusively owned equipment and facilities as provided in Paragraph 4 of Section III entitled "Operator's Exclusively Owned Facilities."

6. *Damages and Losses to Management Area and Equipment*.

All costs or expenses necessary to replace or repair damages or losses incurred by fire, storm, theft, accident, or any other cause not controllable by Continental through the exercise of reasonable diligence. Continental shall fur-

nish Louisiana Gas written notice of damages or losses incurred as soon as practicable after report of the same has been received by Continental.

7. *Litigation Expense*

All costs and expenses of litigation and legal services, including attorneys' fees for outside services and the salaries and expenses of staff attorneys working in connection with the management area and actual expenses incurred in securing evidence where such expenses are incurred by Continental, and necessary in connection with the management service undertaken.

8. *Taxes*

All taxes of every kind and nature paid by Continental in the discharge of the obligations undertaken.

9. *Insurance*

Premiums paid for insurance carried, together with all expenditures incurred and paid in settlement of any and all losses, claims, damages, judgments, and other expenses, including legal services, not recovered from insurance carrier.

10. *District and Camp Expense*

A proportionate share of the salaries and expenses of Continental's District Superintendent and other general district or field employees serving the management area, whose time is not allocated direct to the management area, and a proportionate share of maintaining and operating a district office and all necessary camps, including housing facilities for employees if necessary, in conducting the operations on the management area and other leases and facilities operated by Continental in the same locality. The

expense of, less any revenue from, these facilities shall include depreciation or a fair monthly rental in lieu of depreciation on the investment. Such charges shall be apportioned to all leases and facilities served on some equitable basis consistent with Continental's accounting practice.

II. Administrative Overhead

Continental shall have the right to assess the management area covered hereby the following management and administrative overhead charges, which shall be in lieu of all expenses of all offices of Continental not covered by Section II, Paragraph 10, above, including salaries and expenses of personnel assigned to such offices, except that salaries of geologists and other employees of Continental who are temporarily assigned to and directly serving on the management area will be charged as provided in Section II, Paragraph 1, above. Salaries and expenses of other employees assigned to such offices will be considered as covered by overhead charges in this paragraph.

3837

A. $500 per month for each drilling well.

B. $75 per month for each producing well.

In connection with overhead charges, the status of wells shall be as follows:

(1) Injection wells for recovery operations, such as for repressure or water flood, shall be included in the overhead schedule the same as producing wells.

(2) Water supply wells utilized for water flooding operations shall be included in the overhead schedule the same as producing wells.

(3) Wells permanently shut down but on which plugging operations are deferred shall be dropped from the

overhead schedule at the time the shutdown is effected. When such wells are plugged, overhead shall be charged at the producing well rate during the time required for the plugging operation.

(4) Wells being plugged back, drilled deeper, or converted to a source or input well shall be included in the overhead schedule the same as drilling wells.

(5) Temporarily shut-down wells (other than by governmental regulatory body) which are not produced or worked upon for a period of a full calendar month shall not be included in the overhead schedule; however, wells shut in by governmental regulatory body shall be included in the overhead schedule only in the event the allowable production is transferred to other wells on the same property. In the event an allowable for the entire management area is established, all wells capable of producing from the management area will be counted in determining the overhead charge.

(6) Wells completed in dual or multiple horizons shall be considered as two wells in the producing overhead charge.

(7) Lease salt water disposal wells shall not be included in the overhead schedule unless such wells are used in a secondary recovery program on the management area.

C. The above overhead schedule for producing wells shall be applied to the total number of wells operated under the Management Agreement to which this accounting procedure is attached, irrespective of individual leases.

12. *Other Expenditures*

Any expenditure, other than expenditures which are covered and dealt with by the foregoing provisions of this Section II, incurred by Continental for the necessary and proper development, maintenance, and operation of the management area.

13. *Continental's Warehouse Expense*

None except clerical labor included in district expense.

III. Basis of Charges to Management Area

1. *Purchases*

Material and equipment purchased and service procured shall be charged at price paid by Continental, after deduction of all discounts actually received.

2. *Material Furnished by Continental*

Material required for operations shall be purchased for direct charge to the management area whenever practicable, except that Continental may furnish such material from Continental's stocks under the following conditions:

A. New Material (Condition "A")

(1) New material transferred from Continental's warehouse or other properties shall be priced f.o.b. the nearest reputable supply store or railway receiving point where such material is available at current replacement cost of the same kind of material. This will include material such as tanks, rigs, pump, sucker rods, boilers and engines. Tubular goods (2" and over) shall be priced on the following basis:

(a) On carload basis effective at date of transfer and f.o.b. railway receiving point nearest the management area, regardless of quantity transferred, if material was originally received in Continental's account at all rail rate.

(b) If tubular goods are received in Continental's storage point by barge and moved to the management area by barge, rail or truck it shall be priced at current mill price at date of transfer plus barge rate and stevedoring and storage costs at storage point and the barge, rail or truck rates to the management area, according to transportation facilities used, regardless of quantity transferred.

(2) Other material shall be priced on basis of a reputable supply company's preferential price list effective at date of transfer and f.o.b. the store or railway receiving point nearest the management area where such material is available.

(3) Cash discount shall not be allowed.

B. Used Material (Condition "B" and "C")

(1) Material which is in sound and serviceable condition and is suitable for reuse without reconditioning shall be classed as Condition "B" and priced at 75% of new price. Tubular goods (2" and over) shall be priced at 75% of current new price at date of transfer on basis of carload mill shipment f.o.b. nearest railway receiving point to the management area.

(2) Material which cannot be classified as Condition "B" but which,

(a) After reconditioning will be further serviceable for original function as good second-hand material (Condition "B"), or

(b) Is serviceable for original function but substantially not suitable for reconditioning, shall be classed as Condition "C" and priced at 50% of new price.

(3) Material which cannot be classified as Condition "B" or Condition "C" shall be priced at a value commensurate with its use.

(4) Tanks, derricks, buildings, and other equipment involving erection costs shall be charged at applicable percentage of knock-down new price.

3. *Warranty of Material Furnished by Continental*

Continental does not warrant the material furnished beyond or back of the dealer's or manufacturer's guaranty; and, in case of defective material, credit shall not be passed until adjustment has been received by Continental from the manufacturers or their agents.

3839

4. *Continental's Exclusively Owned Facilities*

The following rates shall apply to service rendered to the management area by facilities owned exclusively by Continental:

A. Water service, fuel gas, power, and compressor service: At rates commensurate with cost of providing and furnishing such service to the management area but not exceeding rates currently prevailing in the field where the management area is located.

B. Automotive Equipment: Rates commensurate with cost of ownership and operation. Such rates should gen-

erally be in line with schedule of rates adopted by the Petroleum Motor Transport Association, or some other recognized organization, as recommended uniform charges against the management area operations and revised from time to time. Automotive rates shall include cost of oil, gas, repairs, insurance and other operating expense and depreciation; and charges shall be based on use in actual service on, or in connection with, the management area. Truck, tractor, and pulling unit rates shall include wages and expenses of driver.

C. A fair rate shall be charged for the use of drilling and cleaning out tools and any other items of Continental's fully owned machinery or equipment which shall be ample to cover maintenance, repairs, depreciation, and the service furnished the management area; provided that such charges shall not exceed those currently prevailing in the field where the management area is located.

D. Whenever requested, Continental shall inform Louisiana Gas, or its representative, in advance of the rates it proposes to charge.

E. Rates shall be revised and adjusted from time to time when found to be either excessive or insufficient.

IV. Disposal of Lease Equipment and Material

Continental shall be under no obligation to purchase from Louisiana Gas surplus, new or used equipment, material or supplies. If Continental determines that any such surplus exists, Continental shall, at its option, purchase same at such price and on the same conditions as same can be sold, or sell such surplus. Any sum chargeable to Continental for surplus materials purchased, or any sum received by Continental from the sale of such surplus materials, shall be credited to Louisiana Gas on the next monthly statement.

V. Basis of Pricing Material Transferred From Management Area

Material purchased by Continental, unless otherwise agreed, shall be valued on the following basis:

1. *New Price Defined*

New price as used in the following paragraphs shall have the same meaning and application as that used above in Section III, "Basis of Charges to Management Area."

3840

2. *New Material*

New material (Condition "A"), being new material procured for the management area but never used thereon, at one hundred per cent (100%) of current new price (plus sales tax, if any).

3. *Good Used Material*

Good used material (Condition "B"), being used material in sound and serviceable condition, suitable for reuse without reconditioning.

A. At seventy-five per cent (75%) of current new price.

4. *Other Used Material*

Used material (Condition "C"), at fifty per cent (50%) of current new price, being used material which:

A. After reconditioning will be further serviceable for original function as good secondhand material (Condition "B"), or

B. Is serviceable for original function but substantially not suitable for reconditioning.

5. *Bad Order or Junk Material*

Material and equipment (Condition "D"), which is no longer usable for its original purpose or junk being obsolete and scrap material shall be disposed of prior to removal from the location at which it was used.

6. *Temporarily Used Material*

When the use of material is temporary and its service to the management area does not justify the reduction in price as provided above, such material shall be priced on a basis that will leave a net charge to the management area consistent with the value of the service rendered.

VI. Inventories

1. *Periodic Inventories*

Periodic inventories shall be taken by Continental of the material on the management area which shall include all such material as is ordinarily considered controllable by operators of oil and gas properties.

2. *Notice*

Notice of intention to take inventory shall be given by Continental at least ten (10) days before any inventory is to begin so that Louisiana Gas, or its representatives, may be represented when any inventory is taken.

3. *Failure to be Represented*

Failure of Louisiana Gas, or its representatives, to be represented at the physical inventory shall bind Louisiana Gas to accept the inventory taken by Continental, who shall in that event furnish Louisiana Gas, or its representatives, with a copy thereof.

3841

4. *Reconciliation of Inventory*

Reconciliation of inventory with charges to the management area shall be made by each party, and a list of overages and shortages shall be jointly determined by Continental and Louisiana Gas, or its representatives.

5. *Adjustment of Inventory*

Inventory adjustment shall be made by Continental for overages and shortages, but Continental shall only be held accountable to Louisiana Gas for shortages due to lack of reasonable diligence.

3842

CONSENT TO ASSIGN MANAGEMENT AGREEMENT

Continental Oil Company, hereinafter referred to as "Continental" consents to and approves of the assigning by Louisiana Gas Corporation, hereinafter referred to as Louisiana Gas", all of the rights and obligations of Louisiana Gas under the attached Management Agreement between Louisiana Gas and Continental to Texas Eastern Transmission Corporation, hereinafter referred to as "Texas Eastern", with the understanding that:

1. Any assignment of the Management Agreement by Texas Eastern, without the prior approval of Continental, shall give Continental, subject to the remaining provisions of Article 4, the right to cancel under the provisions of subparagraph (a) of Article 4;

2. Texas Eastern shall be responsible for the obligations of the said agreement so long as, but only to the extent that, the obligations accrue during the time the

leasehold rights affected thereby are held by Texas Eastern.

CONTINENTAL OIL COMPANY
By O. L. FISHER
Vice President

LOUISIANA GAS CORPORATION
By CAMPBELL A. GRIFFIN
President

TEXAS EASTERN TRANSMISSION CORPORATION
By JOHN C. JACOBS
Vice President

TEXAS EASTERN TRANSMISSION CORPORATION

DISPOSITION OF PAYNE FIELD GAS PRODUCTION
FROM JULY, 1959 THROUGH AUGUST, 1961

		(1) TOTAL FIELD PRODUCTION MCF	(2) LESS: GAS DELIVERED TO OTHER PIPELI.. MCF	(3) PLUS: GAS REC'D FROM OTHER SOURCES MCF	(4) LESS: GAS DISPOSED OF IN FIELD MCF	(5) TOTAL TO PLANT MCF	DISPOSITION OF GAS (6) FUEL FROM DE-ETHANIZER MCF	(7) FUEL FROM DE-METHANIZER MCF	(8) SHRINKAGE MCF	(9) DRILLING FUEL MCF
1959	July	497,978	434,643	1,763	-	-	-	-	-	-
	August	1,469,636	-	1,173	-	-	-	-	-	-
	September	3,692,321	-	2,755	-	-	-	-	-	-
	October	3,731,631	-	1,466	-	-	-	-	-	-
	November	3,524,885	-	1,274	-	-	-	-	-	-
	December	3,708,479	-	1,572	-	-	-	-	-	-
1959	Total	16,624,930	434,643	10,303	-	-	-	-	-	-
1960	January	3,178,885	-	96	-	-	-	-	-	2,648
	February	3,614,742	-	-	-	-	-	-	-	5,906
	March	3,609,300	-	103	4,204	-	-	-	-	5,106
	April	3,083,957	-	391	4,204	-	-	-	-	4,269
	May	3,533,045	-	826	4,204	-	-	-	-	2,168
	Sub-Total	17,019,929	-	1,496	12,352	-	-	-	-	20,257
	June	3,363,429	-	1,303	5,609	3,359,043	2,232	-	6,336	-
	July	3,966,276	-	704	4,301	3,962,599	42,624	-	[illegible],469	23
	August	4,277,717	77,871	1,523	4,733	4,196,636	49,626	-	70,969	2,307
	September	3,937,554	107,176	647	4,602	3,826,343	50,406	-	40,671	-
	October	4,256,702	140,422	1,276	5,314	4,112,242	53,020	-	155,678	-
	November	4,154,924	108,684	83	5,243	4,041,080	53,362	-	67,744	-
	December	4,516,149	101,449	371	5,294	4,409,777	39,924	25,013	36,848	-
	Sub-Total Jun - Dec	28,472,751	535,602	5,907	35,336	27,907,720	291,344	25,013	495,715	2,330
1960	Total	45,492,680	535,602	7,403	40,188	27,907,720	291,344	25,013	495,715	22,587
1961	January	4,640,088	96,394	-	5,202	4,538,492	26,803	39,092	29,339	-
	February	3,761,885	131,271	-	5,151	3,625,463	19,720	28,973	43,972	-
	March	4,149,346	100,031	-	4,096	4,044,419	32,329	38,319	95,840	549
	April	4,035,774	87,325	-	5,126	3,943,323	30,573	34,493	81,178	38,637
	May	3,112,810	96,500	-	5,253	3,011,057	21,755	45,049	99,276	42,925
	June	3,002,317	86,321	-	5,253	2,910,743	10,747	45,990	70,660	35,469
	July	2,893,650	100,585	-	4,743	2,788,322	14,241	47,085	98,887	29,368
	August	4,465,566	99,242	-	4,743	4,361,581	21,187	48,901	129,703	26,725
1961	Total	30,061,436	797,669	-	40,367	29,223,400	177,363	328,710	648,855	173,673
Total Prior to Plant Oper.		33,644,859	434,643	11,799	12,852	-	-	-	-	20,257
Total After Plant In Oper.		58,534,187	1,333,271	5,907	75,703	57,131,120	468,707	354,523	1,144,570	176,003
Grand Total		92,179,046	1,767,914	17,706	88,555	N.A.	468,707	354,523	1,144,570	196,260

NOTE: Source of Information as Follows:

1. Columns 1, 2, 3 and 4 from Louisiana Dept. of Conservation Form R5P & R6.
2. Columns 5, 6, 7, 8, 9 and 10 from Louisiana Dept. of Conservation Form R6.
3. Columns 12 and 13 from Louisiana Dept. of Conservation Form R1 & R6.

Hearing Exhibit X-20 X - 20 (3843)

TEXAS EASTERN TRANSMISSION CORPORATION

DISPOSITION OF RAYNE FIELD GAS PRODUCTION
FROM JULY, 1959 THROUGH AUGUST, 1961

Filed with Hrs. Certification dated JUN 29 1962

	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				DISPOSITION OF GAS							
GAS ...D TO FIELD...	PLUS: GAS REC'D FROM OTHER SOURCES MCF	LESS: GAS DISPOSED OF IN FIELD MCF	TOTAL TO PLANT MCF	FUEL FROM DE-ETHANIZER MCF	FUEL FROM DE-METHANIZER MCF	SHRINKAGE MCF	DRILLING FUEL MCF	HEATER FUEL MCF	DELIVERED TO PIPELINE MCF	CONDENSATE PRODUCTION BBLS	PLANT PRODUCTS BBLS
643	1,763	-	-	-	-	-	-	-	65,098	25,310	-
	1,173	-	-	-	-	-	-	-	1,470,809	70,529	-
	2,755	-	-	-	-	-	-	-	3,695,076	171,711	-
	1,466	-	-	-	-	-	-	1,130	3,731,967	176,625	-
	1,274	-	-	-	-	-	-	2,529	3,523,630	170,820	-
	1,872	-	-	-	-	-	-	3,240	3,707,111	186,708	-
643	10,303	-	-	-	-	-	-	6,899	16,193,691	801,703	-
	96	-	-	-	-	-	2,640	3,208	3,173,065	162,439	-
	-	-	-	-	-	-	5,906	2,044	3,605,912	182,061	-
	103	4,284	-	-	-	-	5,106	3,204	3,596,729	186,958	-
	391	4,284	-	-	-	-	4,269	2,493	3,073,302	162,402	-
	826	4,284	-	-	-	-	2,168	2,203	3,525,216	184,338	-
	1,496	12,852	-	-	-	-	20,257	14,092	16,974,224	878,198	-
	1,303	5,609	3,359,043	2,232	-	6,836	-	1,323	3,349,152	172,061	9,724
	704	4,301	3,962,599	42,624	-	97,469	23	-	3,822,483	188,900	81,531
871	1,523	4,733	4,196,636	49,626	-	70,969	2,307	-	4,073,734	203,234	91,600
176	647	4,682	3,826,343	50,406	-	40,671	-	603	3,734,583	184,087	94,438
422	1,276	5,314	4,112,242	53,020	-	155,678	-	414	3,903,130	197,268	103,916
604	83	5,243	4,041,080	53,362	-	87,744	-	538	3,899,436	188,906	96,956
449	371	5,294	4,409,777	39,944	25,813	36,848	-	606	4,306,516	208,879	113,913
602	5,907	35,336	27,907,720	291,344	25,813	495,715	2,330	3,484	27,089,034	1,343,335	592,078
602	7,403	48,188	27,907,720	291,344	25,813	495,715	22,587	17,576	44,063,258	2,221,533	592,078
394	-	5,202	4,538,492	26,803	39,092	29,339	-	587	4,441,871	214,245	123,273
271	-	5,151	3,625,463	19,720	28,973	43,972	-	504	3,532,286	170,591	78,840
031	-	4,096	4,044,419	32,329	38,319	95,840	549	541	3,876,841	193,374	120,041
325	-	5,126	3,943,323	30,573	34,493	81,178	38,637	267	3,758,175	185,930	110,095
500	-	5,253	3,011,057	21,755	45,049	99,276	42,925	335	2,801,719	132,094	89,234
321	-	5,253	2,910,743	10,747	45,990	70,660	35,469	327	2,747,542	133,685	81,324
585	-	4,743	2,780,322	14,241	47,085	98,887	29,368	334	2,598,407	128,530	84,344
242	-	4,743	4,361,581	21,187	48,901	129,703	26,725	358	4,134,707	199,556	123,406
569	-	40,367	29,223,400	177,363	328,710	648,855	173,673	3,251	27,891,548	1,358,005	810,557
543	11,799	12,852	-	-	-	-	20,257	20,991	33,167,915	1,679,901	-
271	5,907	75,703	57,131,120	468,707	354,523	1,144,570	176,003	6,735	54,980,582	2,701,340	1,402,635
814	17,706	88,555	N.A.	468,707	354,523	1,144,570	196,260	27,726	88,148,497	4,381,242	1,402,635

of Conservation Form R5P & R6.
a Dept. of Conservation Form R6.
Conservation Form R1 & R6.

3844

Hearing Exhibit No. X-21

TEXAS EASTERN TRANSMISSION CORPORATION
RAYNE FIELD

HISTORY OF WELL DESIGNATIONS

New Names

Effective October 1, 1961

1.	KLMP	A	SU	A-E	Quebodeaux No. 1
2.	KLMP	D	SU	A-W	Petitjean Co. No. 1[9]
3.	KLMP	D	SU	B-ED	Arceneaux No. 2
4.	KLMP	D	SU	C-E	Arceneaux No. 1
5.	KLMP	D	SU	D-W	Petitjean Co. No. 4-D
6.	HMSK	D2	SU	A-M	G. Navarre A No. 1
7.	HMSK	D2	SU	B-J	W. Arceneaux No. 1
8.	HMSK	E	SU	A-J	S. Arceneaux No. 1
9.	HMSK	E	SU	B-D	Cormier No. 1
10.	HMSK	E	SU	C-T	G. Petitjean No. 2
11.	HMSK	E	SU	D-W	Petitjean Co. No. 3
12.	HMSK	E	SU	E-A	Meche No. 1
13.	HMSK	E	RA	SU A-E	Arceneaux No. 1
14.					Marie Petitjean No. 1 XX[8]
15.	NOD	A	SU	A-W	Petitjean Co. No. 2
16.	NOD	A	SU	B-T	G. Petitjean No. 1
17.	NOD	A	SU	C-G	Mouton No. 1
18.	NOD	A	SU	D-A	R. Blanhcard No. 1
19.	NOD	A	SU	E-D	Cormier No. 2
20.	NOD	A	SU	F-E	Dupuis No. 1
21.	NOD	A	SU	G-C	Dugas No. 1
22.	NOD	A	SU	H-L	Cormier No. 1
23.	NOD	A	SU	I-R	E. Babineaux No. 1